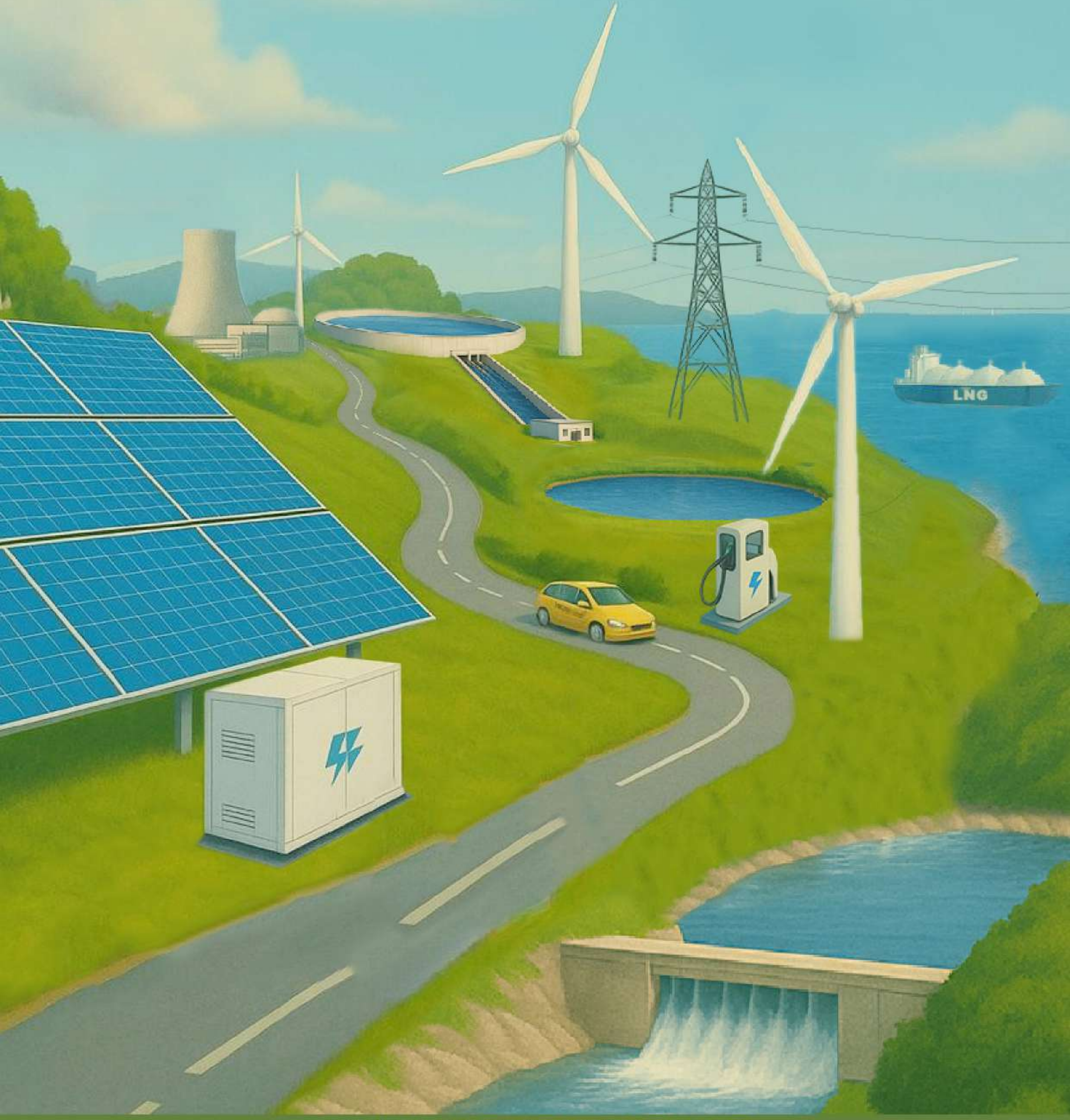
LONG TERM GENERATION EXPANSION PLAN 2025-2044



CEYLON ELECTRICITY BOARD

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LONG TERM GENERATION EXPANSION PLAN

2025-2044

Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka
May 2025

Long Term Generation Expansion Planning Studies
2025- 2044

Compiled and prepared by
The Generation Planning Unit
Transmission and Generation Planning Branch
Ceylon Electricity Board, Sri Lanka

Submitted for the approval to PUCSL on 4th September 2024

Approval granted by PUCSL on 15th May 2025
Supplementary Information provided to PUCSL are included in Annex 16 and the content of this final report amended incorporating the recommendations of PUCSL (Annex 17)

ISSN 2989-0012

Long-term generation expansion planning studies are carried out every two years by the Transmission & Generation Planning Branch of the Ceylon Electricity Board, Sri Lanka and this report is a biennial publication based on the results of the latest expansion planning studies. The data used in this study and the results of the study, which are published in this report, are intended purely for this purpose.

Foreword

The Report on 'Long Term Generation Expansion Planning Studies 2025-2044', presents the results of the latest expansion planning studies conducted by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the planning period 2025-2044, and replaces the Long Term Generation Expansion Plan 2023-2042.

This report, gives a comprehensive view of the existing generating system, future electricity demand and future power generation options in addition to the expansion study results.

The latest available data were used in the study. The Planning Team wishes to express their gratitude to all those who have assisted in preparing the report. We would welcome suggestions, comments and criticism for the improvement of this publication.

Transmission and Generation Planning Branch
5th Floor, Head Office Bldg.
Ceylon Electricity Board
Sir Chittampalam A. Gardinar Mw.
Colombo 02

e-mail: cegptgp.tr@ceb.lk
Tel: +94-11-2329812
Fax: +94-11-2434866

Prepared by:

Generation Planning Unit

Chief Engineer
Eng. K.H.E.H. Jayarathna

Electrical Engineers
Eng. (Ms.) M.D.V. Fernando
Eng. K.H.A. Kaushalya
Eng. K.A.M.N. Pathiratne
Eng. (Ms.) G.R.A.P. Weerasinghe
Eng. (Ms.) D.P. Liyanage

Reviewed by:

Eng. W.M.K.D.S. Fernando
Additional General Manager (Transmission Non-Wired Operations)

Eng. K.G.R.F. Comester
Former Additional General Manager (Transmission Non-Wired Operations)

Eng. (Dr.) H.M. Wijekoon Banda
Deputy General Manager (Transmission & Generation Planning)

Any clarifications sought or request for copies of the report should be sent to the Deputy General Manager (Transmission and Generation Planning) at the address above.

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ACRONYMS

ADB	-	Asian Development Bank
API	-	Argus/McCloskey's Coal price Index
bcf	-	Billion Cubic Feet
BESS	-	Battery Energy Storage System
BOO	-	Build, Own and Operate
BOOT	-	Build, Own, Operate and Transfer
CAGR	-	Cumulative Annual Growth Rate
CCY	-	Combined Cycle Power Plant
CEA	-	Central Environmental Authority
CEB	-	Ceylon Electricity Board
CECB	-	Central Engineering Consultancy Bureau
CIDA	-	Canadian International Development Agency
CIF	-	Cost, Insurance and Freight
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction
COP	-	Conference of Parties
CPC	-	Ceylon Petroleum Cooperation
DAM	-	Day Ahead Market
DSM	-	Demand Side Management
EIA	-	Environmental Impact Assessment
ENS	-	Energy Not Served
EOI	-	Expression of Interest
ESP	-	Electrostatic Precipitator
FACTS	-	Flexible Alternating Current Transmission System
FGD	-	Flue Gas Desulphurization
FO	-	Furnace Oil
FOB	-	Free On Board
FOR	-	Forced Outage Rate
FSRU	-	Floating Storage Regasification Unit
GCV	-	Gross Calorific Value
GDP	-	Gross Domestic Product
GHG	-	Green House Gases
GIS	-	Geographic Information System
GT	-	Gas Turbine
HHV	-	Higher Heating Value
HVDC	-	High Voltage Direct Current
IAEA	-	International Atomic Energy Agency
IC	-	Internal Combustion
IDC	-	Interest During Construction
IEA	-	International Energy Agency
IMF	-	International Monetary Fund
INDC	-	Intended Nationally Determined Contributions
IPCC	-	Inter-Governmental Panel on Climate Change
IPP	-	Independent Power Producer
JBIC	-	Japan Bank for International Cooperation

JCC	-	Japan Crude Oil Cocktail
JICA	-	Japan International Cooperation Agency
JKM	-	Japanese Korean Marker
LKR	-	Sri Lanka Rupees
KPS	-	Kelanithissa Power Station
LCC	-	Line Commutated Converter
LCOE	-	Levelised Cost of Electricity
LDC	-	Load Duration Curve
LF	-	Load Factor
LNG	-	Liquefied Natural Gas
LOLP	-	Loss of Load Probability
LPG	-	Liquefied Petroleum Gas
LTGEP	-	Long Term Generation Expansion Plan
MAED	-	The Model for Analysis of Energy Demand
masl	-	Meters Above Sea Level
MMBTU	-	Million British Thermal Units
MMSCFD	-	Million Standard Cubic Feet per Day
MTPA	-	Million Tons Per Annum
NDC	-	Nationally Determined Contributions
NEPS	-	National Energy Policy and Strategy
NG	-	Natural Gas
NPP	-	Nuclear Power Plant
OECD	-	Organization for Economic Co-operation and Development
OECF	-	Overseas Economic Co-operation Fund
ORE	-	Other Renewable Energy
OTEC	-	Ocean Thermal Energy Conversion
O&M	-	Operation and Maintenance
PF	-	Plant Factor
PM	-	Particulate Matter
PPA	-	Power Purchase Agreement
PRDS	-	Petroleum Resources Development Secretariat
PSPP	-	Pumped Storage Power Plant
PUCSL	-	Public Utilities Commission of Sri Lanka
PV	-	Photovoltaic
RE	-	Renewable Energy
RFP	-	Request For Proposals
ROCOF	-	Rate of Change of Frequency
RTC	-	Round the Clock
SAM	-	System Advisor Model
SCR	-	Selective Catalytic Reduction
SDDP	-	Stochastic Dual Dynamic Programming
SNSP	-	System Non Synchronous Penetration
SPPA	-	Standardized Power Purchase Agreement
ST	-	Steam Turbine
STATCOM	-	Static Synchronous Compensator
TC	-	Technical Cooperation
tcf	-	Trillion Cubic Feet

UNFCCC	-	United Nations Framework Convention on Climate Change
USAID	-	United States Agency for International Development
USD	-	American Dollars
WB	-	World Bank
WHO	-	World Health Organization
VRE	-	Variable Renewable Energy
VSC	-	Voltage Source Converter

EXECUTIVE SUMMARY

INTRODUCTION

The Long-Term Generation Expansion Plan, is a biennial publication prepared by Ceylon Electricity Board, which outlines the generating capacity requirement of the power sector during the two decades ahead, to realise a secure, reliable, economical and sustainable supply of electricity, while adhering to the government policies and environmental obligations of the country. The Long-Term Generation Expansion Plan (LTGEP) covers a planning horizon of 20 years.

LTGEP 2025-2044 presents result of the generation expansion planning studies carried out by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the period 2025-2044. The report also includes information on the existing generation system, the generation planning methodology, system demand forecast and the investment requirement and implementation plans for the proposed projects. Out of different possible scenarios, the plan recommends the adoption of the most justifiable generation mix for the future (titled the "Base Case" scenario) that also comply with the government policy pertaining to the electricity industry. This report also contains results of contingency analysis to prepare for possible contingency events (that are not captured in the Base Case scenario) but having a likelihood to occur in the near term. Key actions required and recommendations are separately presented at the end of this executive summary.

PREVAILING GOVERNMENT POLICY GUIDELINES

As stipulated in the Generation Planning Code (which is a part of the Grid Code), it is mandatory to follow the applicable government policy when conducting planning studies. The current policy for the electricity industry is contained in the document "The General Policy Guidelines in Respect of the Electricity Industry" as approved by the Cabinet of Ministers in November 2021 and issued by the Ministry of Power in January 2022. The government policy contains 04 clauses that are directly related to the future generating mix as proposed in this LTGEP report. The energy mix proposed through the Base Case scenario of LTGEP 2025-2044 is in alignment to all such policy requirements as indicated below.

1. Achieve 70% of electricity generation in the country using renewable energy (RE) sources by 2030
2. Achieve carbon neutrality in power generation by 2050
3. Cease building of new coal-fired power plants
4. New addition of firm capacity will be from clean energy sources such as regasified liquefied natural gas (RLNG)

PLANNING APPROACH

Sri Lanka's electricity sector is essential to sustaining the nation's economy and providing energy to its people, contributing approximately 14% to the country's overall energy demand. The sector has evolved significantly, transitioning from a foundation of traditional thermal and hydroelectric power generation to a stronger focus on expanding renewable energy sources.

The Ceylon Electricity Board has consistently adopted a forward looking approach in its long-term planning for the electricity sector. This approach involves conducting detailed studies well in advance to explore various technological and fuel options that could be considered in future planning. The goal has consistently been to ensure that the most suitable options are incorporated into the long-term generation expansion plans when the timing is right, both technologically and economically.

In recent years, the planning approach has shifted significantly to accommodate the increasing need to integrate a high percentage of renewable energy into the power system, driven by policy mandates. The current strategy is focused on achieving this ambitious renewable energy target by implementing the necessary grid interventions at the lowest possible economic cost, while ensuring the reliability and security of the power system.

The planning horizon includes a comprehensive roadmap, as shown in Figure E1, that outlines the key interventions required to facilitate this paradigm shift towards a more clean and sustainable energy future. These interventions are designed to support the gradual transition to higher share of clean energy penetration, ensuring that the system can absorb and manage this increased share of renewables without compromising its stability or performance.

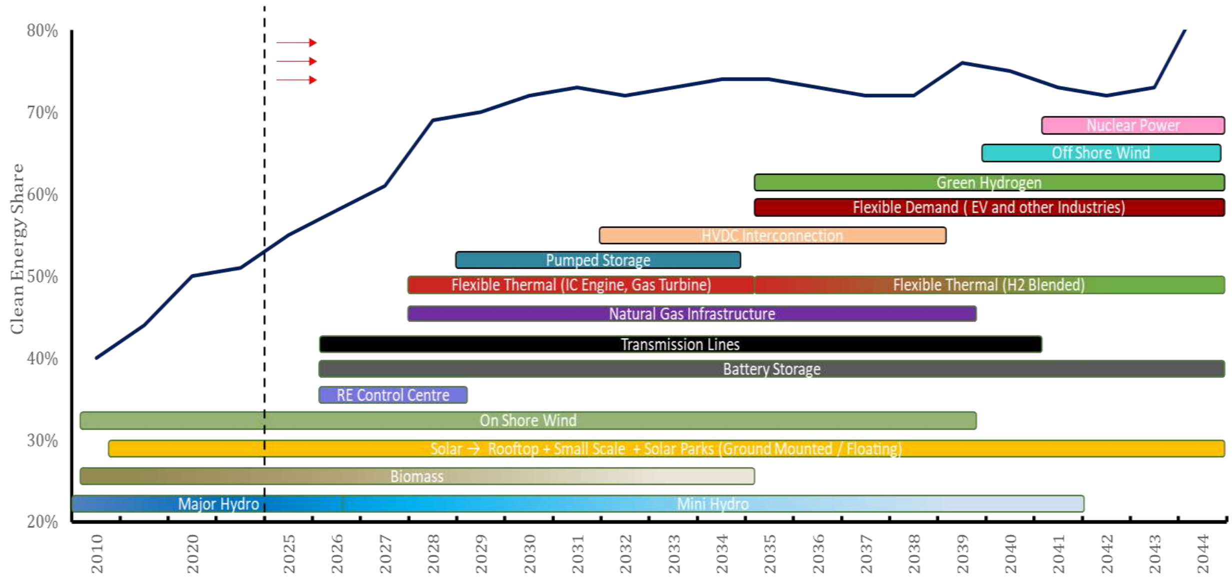


Figure E1 –Roadmap of Interventions in Base Case Scenario

The planning studies have been prepared with detailed studies in different time frames while maintaining reliability criteria within the stipulated limits. Sufficient reserve capacity is ensured to ensure the Loss of Load Probability remains within published criteria during the critical periods of each year.

MEETING CLIMATE CHANGE OBLIGATIONS

The 20-year development plan presented in this report meets all the environmental and climate change obligations of Sri Lanka during its 20-year planning horizon. In response to the climate change challenges, Sri Lanka too has taken several initiatives by introducing national policies, strategies and actions to mitigate the impacts. Sri Lanka, being a partner to COP21 Paris agreement on mitigation of global climate change induced impacts, presented its 1st Nationally Determined Contributions (NDC) for the electricity sector in September 2016 to strengthen global efforts, expressing a commitment of 4% unconditional and 16% conditional reduction of GHG emissions compared to the business as usual (BAU) scenario of LTGEP 2013-2032. The country further enhanced its commitments through the updated NDC submission for electricity sector in September 2021, by unconditionally reducing GHG emissions by 5% and conditionally by 20% as compared to the BAU. The Base Case scenario, once fully implemented, expects to reduce the GHG emissions beyond 25% and thus fully capable of meeting the enhanced target.

DEMAND FORECAST

Electricity demand for the period of 2025-2049 was forecasted considering a combination of medium term and long-term forecasting approaches. Five-year sales forecast of CEB and LECO distribution licensees, and time series approach were used to determine the medium-term forecast by further considering the factors such as temperature dependant seasonality and shock impact on economy due to financial crisis. Econometric approach was used for long term forecast.

Demand for electricity in the country has been growing at an average rate of about 3.8% per annum during the last fifteen years, while peak demand has been growing at a rate of 1.9% per annum on average. However, it should be noted that during the last three years period same has shown a reduction of 3.5% and 7.2% respectively due to recent economic crisis of the country. As per demand projections, the growth is expected to continue at an average rate of 4.8% in the long run. The changes in daily electricity demand pattern reveals the trend of the day time demand is becoming prominent and is anticipated to surpass the night peak and become the dominant peak beyond 2024.

Table E1 - Base Demand Forecast 2025-2049

Year	Demand[1]	Net Loss[2]	Net Generation		Day Peak		Night Peak
	GWh	%	GWh	Growth Rate (%)	MW	Growth Rate (%)	MW
2025	16,319	7.93	17,725	5.2	2,727	5.3	2,696
2026	17,203	7.76	18,650	5.2	2,872	5.3	2,824
2027	18,135	7.62	19,630	5.3	3,027	5.4	2,959
2028	19,118	7.48	20,662	5.3	3,190	5.4	3,101
2029	20,153	7.34	21,750	5.3	3,362	5.4	3,250
2030	21,245	7.34	22,927	5.4	3,548	5.5	3,411
2031	22,264	7.33	24,026	4.8	3,722	4.9	3,560
2032	23,329	7.33	25,174	4.8	3,904	4.9	3,714
2033	24,438	7.32	26,369	4.7	4,094	4.9	3,874
2034	25,602	7.32	27,624	4.8	4,294	4.9	4,041
2035	26,842	7.31	28,961	4.8	4,507	5.0	4,219
2036	28,188	7.31	30,411	5.0	4,738	5.1	4,412
2037	29,619	7.31	31,953	5.1	4,985	5.2	4,616
2038	31,141	7.3	33,594	5.1	5,247	5.3	4,833
2039	32,702	7.3	35,275	5.0	5,516	5.1	5,055
2040	34,338	7.29	37,038	5.0	5,798	5.1	5,286
2041	36,058	7.29	38,892	5.0	6,095	5.1	5,528
2042	37,798	7.28	40,767	4.8	6,397	4.9	5,772
2043	39,582	7.28	42,689	4.7	6,706	4.8	6,020
2044	41,424	7.27	44,673	4.6	7,026	4.8	6,275
2045	43,235	7.27	46,624	4.4	7,342	4.5	6,524
2046	45,062	7.26	48,592	4.2	7,660	4.3	6,773
2047	46,922	7.26	50,594	4.1	7,985	4.2	7,025
2048	48,732	7.25	52,544	3.9	8,303	4.0	7,267
2049	50,592	7.25	54,546	3.8	8,630	3.9	7,516
5 Year Avg Growth	5.4%		5.2%		5.4%		4.8%
10 Year Avg Growth	5.1%		5.1%		5.2%		4.6%
20 Year Avg Growth	5.0%		5.0%		5.1%		4.5%
25 Year Avg Growth	4.8%		4.8%		4.9%		4.4%

[1]In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.
[2] Net losses include losses at the Transmission & Distribution levels. Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

SCENARIOS CONSIDERED IN PLANNING STUDIES

To identify Base Case scenario for LTGEP 2025-2044, five specific scenarios were developed within the guidelines specified in the general policy guidelines. The five scenarios developed were:

1. Scenario 1: Maintain 70% RE from 2030 onwards, with 500 MW HVDC interconnection, no coal capacity additions
2. Scenario 2: Maintain 70% RE from 2030 onwards, without HVDC interconnection, no coal capacity additions
3. Scenario 3: Maintain 70% RE from 2030 onwards, with 500 MW HVDC interconnection, with nuclear Power, no coal capacity additions
4. Scenario 4: Achieve 70% RE by 2030 and increase to 80% by 2044, With 1000 MW HVDC interconnection, no coal capacity additions
5. Scenario 5: Achieve 70% RE by 2030, increase to 80% from 2040 onwards, with aggressive solar and BESS development, With 500 MW HVDC interconnection, no coal capacity additions

After evaluation of all aforementioned scenarios, Scenario 3 was selected as the Base Case scenario as it indicated the lowest present value (PV) cost among the above five scenarios and was technically feasible.

In addition, following scenarios were developed to analyse technical and economic implications of complying with the policy guidelines and to ultimately identify the least cost scenarios unconstrained by policy guidelines.

6. Scenario 6: Maintain 65% RE from 2028 onwards, with coal capacity additions
7. Scenario 7: Maintain 60% RE from 2027 onwards, with coal capacity additions
8. Scenario 8: Maintain 60% RE from 2027 onwards, no coal capacity additions

All Scenarios 6, 7 and 8 indicated lower present value cost than the existing policy-based scenarios and Scenario 7 indicated the lowest cost among all eight scenarios. Therefore, Scenario 7 was identified as the Reference Case of LTGEP 2025-2044 as it indicated the lowest present value cost unconstrained by policy guidelines and, operationally feasible.

The Table E2 present the comparison of the long term expansion planning scenarios considered in this LTGEP 2025-2044.

Table E2 - Summary of Planning Scenarios and Present Value cost

	Total Present Value Cost (MUSD)	Difference of Present Value Cost compared to Reference scenario (MUSD)
Scenario 1 Maintain 70% RE from 2030 onwards, With 500 MW HVDC interconnection, No coal capacity additions	15,109	865
Scenario 2 Maintain 70% RE from 2030 onwards, Without HVDC interconnection, No coal capacity additions	15,269	1,025
Scenario 3 (Base Case) Maintain 70% RE from 2030 onwards, With 500 MW HVDC interconnection, With nuclear Power, No coal capacity additions	15,090	846
Scenario 4 Achieve 70% RE by 2030 and increase to 80% by 2044, With 1000 MW HVDC interconnection, No coal capacity additions	15,301	1,057
Scenario 5 Achieve 70% RE by 2030, increase to 80% from 2040 With aggressive solar and BESS development, With 500 MW HVDC interconnection, No coal capacity additions	17,009	2,765
Scenario 6 Maintain 65% RE from 2028 onwards, With coal capacity additions	14,328	84
Scenario 7 Maintain 60% RE from 2027 onwards, With coal capacity additions	14,244	-
Scenario 8 Maintain 60% RE from 2027 onwards, No coal capacity additions	14,369	125

The Table E3 presents the power plant schedule of the base case scenario considered in this LTGEP 2025-2044.

Table E3 - Base Case Scenario 2025-2044

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [a] [b] [d]	THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [a] [c] [e] [f]
2025	Distribution Connected Embedded Solar 150 MW **Grid Connected Solar 50 MW** **Wind 10 MW** Mini Hydro 10 MW Biomass 10 MW Battery Energy Storage 5 MW/10 MWh	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya) 115 MW**
2026	Distribution Connected Embedded Solar 150 MW **Grid Connected Solar 220 MW** **Wind 90 MW** Mini Hydro 10 MW Biomass 15 MW **Battery Energy Storage (Western Region)[1] 100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya) 235 MW** *Retirement of* *Gas Turbine (GT7)[2] (115) MW* *Extensions of plants to be retired[3]* *Sapugaskanda Station A 68 MW* *Sapugaskanda Station B 72 MW* *Barge Mounted Plant 62 MW*
2027	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 260 MW Mini Hydro 10 MW Biomass 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya) 115 MW**
2028	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Wind 200 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage (Southern Region) [4] 100 MW/ 400MWh	**IC Engine Power Plant - Natural Gas 200 MW**
2029	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Wind 150 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage [4] 100 MW/ 400MWh	
2030	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Wind 150 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage (Western Region) [4] 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa 130 MW**
2031	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage 100 MW/400 MWh	Gas Turbine - Natural Gas 100 MW *Retirements of* *Sapugaskanda Station A (68) MW* *Sapugaskanda Station B (72) MW* *Barge Mounted Plant (62) MW*
2032	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage 200 MW/800 MWh	
2033	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage 100 MW/ 400MWh	Gas Turbine - Natural Gas 100 MW *Retirements of* *Combined Cycle Power Plant (KPS) (165) MW* *Combined Cycle Power Plant (KPS-2) (163) MW* *Uthuru Janani Power Plant (26.7) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b) (d)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c) (e) (f)	
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pumped Storage Power Plant (Maha)	150 MW 200 MW 100 MW 20 MW 20 MW 600 MW		
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 100 MW 10 MW 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 100 MW 10 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 250 MW 100 MW 10 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	HVDC Interconnection	500 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 300 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Gas Turbine - Natural Gas & Hydrogen Blend *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	200 MW 300 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 300 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	150 MW 300 MW 500 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	150 MW 300 MW 10 MW 50 MW/200 MWh	Gas Turbine - Natural Gas & Hydrogen Blend Nuclear Power Plant *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	200 MW 600 MW *(300) MW* *(300) MW*

General Notes

a) All plant capacities (MW) shown are the Gross Capacities. Committed Power Projects are shown in bold text and retiring projects are shown in italics with their capacity in brackets.

b) Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities mentioned in the table. Higher capacity additions will be evaluated case by case.

All future wind and grid connected solar shall be procured with necessary grid support capabilities as stipulated in Grid Code. It is required to procure at least 90% of future wind and grid connected solar capacity as projects with capabilities to operate according to the dispatch instructions from national system control centre.

The capacity addition of battery energy storage devices is mainly to provide energy shifting requirements. It could either be developed as stand-alone or co-located with large scale solar parks with dispatch capability from national system control centre. Any additional battery storage capacity could be accommodated at detailed studies after evaluating grid support services requirement such as frequency regulation.

All renewable and storage capacity additions are to be made available during the respective year.

The retirement years of renewable energy capacities are not indicated. However, after the expiry of the PPA, they are expected to be refurbished or replaced with similar capacity from same renewable energy technology.

The retirement years of battery energy storage systems are not indicated. However, they are expected to be replaced with similar capacity, at the end of their lifetime.

c) With the development of LNG supply infrastructure, the existing West Coast power plant (300 MW) and two Kelanithissa combined cycle plants (165 MW and 163 MW) are expected to be converted to natural gas in the mid of 2027. However, the viability of conversion of each power plant should be evaluated separately at the time of the natural gas availability.

Considering the heavy dependency in future on liquefied natural gas as a fuel for electricity generation, all Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply.

All new natural gas fired power plants should have the capability to operate from synthetic fuels such as Hydrogen, to satisfy the policy requirement of achieving carbon neutrality by 2050.

All new natural gas based Combined Cycle Power plants should be technically, operationally and contractually capable of being operated regularly between simple cycle and combined cycle operations.

Dates of all plant additions as contained in the table are the dates considered for planning studies, and considered as added at the beginning (as at 1st January) of the respective year. (For example, a generating capacity addition indicated for year 2026 implies that the plant has been considered commissioned from the 1st of January 2026). However, for committed power projects actual commissioning month has been considered based on the present progress of the project.

Retirement dates of existing firm capacity plants are dates considered as inputs to planning studies. For existing power plants, the actual retirement month/PPA expiry month were considered for studies.

However, the ACTUAL retirement of all power plants is to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

d) Moragolla Power Plant (30 MW) which is under construction is to be commissioned during 2024. Hence it is not shown in the base case and is considered as an existing plant.

e) 17 MWx 4 units of Kelanitissa small GTs are considered to be retired during the year 2024 for planning studies considering the extended lifetime. However, two number of units are expected to be kept as backup for Colombo power restoration in case of an island-wide power failure.

f) Short term supplementary power requirement is not seen during the coming years in this plan. However, short-term supplementary capacity requirement under different contingency events are assessed in the contingency analysis chapter of the LCLTGEP 2025-2044 report. Such requirements too shall be appropriately considered prior to initiating procurement.

Extension of the contracts of existing capacities could be considered as appropriate within the legal framework to meet short term requirement. Technology of supplementary capacity can be opened for both Gas Turbine and IC engine technology or any other dispatchable firm power technology as appropriate at the time of the procurement. Fuel option can be specified as appropriate at the time of procurement for suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.

Specific Notes

1. The battery energy storage system shall be developed primarily to cater immediate requirements of frequency related services and restoration services.

2. Upon retirement of GT7 in 2026, the possibility of retrofitting the asset as a synchronous condenser shall be evaluated.

3. Plant life extensions of Sapaugaskanda Station A, Sapugaskanda Station B and Barge Power Plant was considered in planning studies and these extensions become viable considering the relevant refurbishment costs of each plant.

4. Due to the unforeseen growth in distributed renewable energy resources by the time of approval of LTGEP 2025-2044, provision is allowed to advance/expedite the procurement of these storage capacities considering the declined prices of battery energy storage systems.

RENEWABLE ENERGY CAPACITY ADDITIONS

The proposed long-term generation expansion plan envisions substantial additions to renewable energy capacity throughout the planning horizon. Indigenous renewable energy sources are set to dominate both in terms of capacity and energy production, with a projected 5,335 MW of new capacity to be added between 2025 and 2034, and an additional 5,380 MW from 2035 to 2044.

Solar power will be the primary driver of this expansion, leveraging the island's abundant solar resources. The current capacity of approximately 1,000 MW is expected to grow to nearly 9,000 MW by the end of the planning horizon, through a mix of rooftop, ground-mounted, and floating solar installations. Wind energy will also play a critical role, with gradual development focused on onshore wind projects. However, as the potential for onshore wind is fully harnessed within the planning period, the country will need to explore offshore wind resources beyond 2040. The current wind capacity of about 250 MW is anticipated to increase to approximately 2,600 MW by the end of the planning horizon. Moderate growth is expected from mini-hydro and biomass resources over the next two decades. While this plan outlines year-by-year capacity targets, there are no restrictions on the further development of mini-hydro and biomass plants beyond these targets, provided local grid constraints are addressed.

The ambitious scale of wind and solar development outlined in this plan will position the country among the leading nations in renewable energy generation. However, this growth brings with it the significant challenge of operating and maintaining a power system with such a high proportion of variable renewable energy.

The increasing penetration of renewable energy resources, particularly those that are seasonal and variable, presents significant operational challenges for the power system. As the share of solar and wind increases, the likelihood of energy curtailment is raised. The surplus generation in certain periods are curtailed due to excessive generation beyond the demand or storage capacity. Despite advancements in storage technologies, these solutions alone are not sufficient to entirely prevent curtailment. Starting from 2026, it is anticipated that large-scale curtailments will become a more frequent occurrence. These curtailments will primarily happen during the daytime, especially on Sundays when demand is lower, as well as throughout the week during the high wind season when wind generation peaks. This situation highlights the critical need for strategic planning and operational flexibility in the power system to balance the integration of renewable energy with demand. To address these challenges, it is imperative to establish robust renewable energy curtailment rules within the grid code. These rules should ensure that any necessary downward adjustments to power generation are carried out transparently and equitably, providing a clear framework for when and how curtailments should occur. This includes prioritizing which renewable energy sources should be curtailed first and under what conditions, ensuring that the process is as efficient as possible while minimizing the impact on overall energy production and grid stability.

FLEXIBLE THERMAL GENERATION

The plan proposes natural gas fired Internal Combustion (IC) Engine power plants and Gas Turbine (GT) power plants instead of new Combined Cycle power plants throughout the planning window. 2,330 MW capacity additions from gas turbine power plants and 600 MW from Internal Combustion Engine (IC) based power plants s are to be added during the planning horizon. These plants provide operational flexibility required to integrate higher proportion of renewable energy. IC engine plants support quick ramping up and ramping down which is a requirement in a system having high amount of variable renewable energy sources. Their fast start up capability, is also expected to reduce spinning reserve requirement a pays pivotal role in secondary and tertiary reserves. Gas Turbines mainly play the role of peaker plants while providing ancillary services for maintaining system inertia and tertiary reserves. The plan recommends that all natural gas based power plants shall also have the dual fuel capability, including suitable fuel supply and storage arrangements locally a such secondary fuel, to ensure supply security in case of disruption to LNG supply. Furthermore, both these power generation technologies could be configured to operate on blended hydrogen (hydrogen mixed with natural Gas) providing a pathway to achieve carbon free future.

STORAGE REQUIRMENTS

Implementation of Utility Scale Battery Energy Storage Systems (BESS) primarily for energy shifting purpose which is essential in order to accommodate high level of variable renewable energy in the system. Furthermore, BESS shall be required to provide other ancillary services such as fast frequency response and frequency regulation. BESS are proposed to be developed as standalone systems as well as integrated solutions coupled with large scale grid connected solar power plants. A cumulative BESS capacity addition of approximately 900 MW is envisaged during the planning horizon.

Implementation of Pumped Storage Power Plant (PSPP), which essentially acts as an energy storage providing the same services as BESS. Due to the longer implementation timeline, BESS are introduced in the initial stages of the planning horizon while a 3 x 200 MW capacity PSPP is introduced in year 2034. Pumped storage hydro, that typically has lifespans of over 50 years, is considered a long term grid support solution for the country.

INTERCONNECTING NATIONS

The development of a 500 MW interconnection between India and Sri Lanka is planned for the second decade of the planning horizon. This strategic initiative aims to foster regional cooperation, enhance energy security, and reduce the reliance on fossil fuels. By enabling the integration of renewable energy across borders, this interconnection will play a vital role in advancing sustainability goals for both nations, while also contributing to the broader regional effort to transition toward cleaner energy sources.

ROADMAP FOR NUCELAR POWER

The gradual phasing out of coal power plants in the later stages of the planning horizon creates an opportunity for the introduction of nuclear power technology. As a reliable and clean energy source, nuclear power plays a crucial role in the pathway toward full decarbonization of the electricity sector. While nuclear projects are highly capital-intensive, they become increasingly viable as one of the few remaining options for achieving carbon neutrality. However, the development of nuclear power requires a significant lead time, involving careful negotiations with all stakeholders and securing public acceptance of the technology. This long gestation period is essential to ensure that the project aligns with environmental goals and societal expectations.

GRID SUPPORT INTERVENTIONS

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plants with the expected reliability. Securing funding and timely implementation of these critical transmission infrastructure projects is essential for commissioning of power projects.

Early introduction of a "Renewable Energy Desk" to the system control centre is mandatory with controlling and monitoring facilities to separately manage RE capacities that are going to be integrated in large proportions. Introduction of solar and wind forecasting is essential feature of the Renewable Energy Desk. Furthermore, Renewable Energy Desk shall have facilities to schedule the generation and curtailments of renewable energy sources transparently among power projects.

Amending power purchase agreements to have curtailments and seasonal tariff adjustments is necessary to achieve smooth and efficient operation power system. It is required to periodically review and upgrade the existing interconnection and operating codes, planning codes and regulations based on detailed studies and up-to-date industry practices.

The excessive curtailments observed even after the integration of storage sources mandates more studies towards incorporating long duration storage sources such as hydrogen. This requires detailed feasibility studies to be conducted on its production patterns, storage mechanisms and potential applications to Sri Lanka including power generation, transportation, industrial applications and production of fertilizer.

Introducing demand response methods with flexible loads such as electric vehicles, desalination plants, hydrogen production shall be necessary for altering the demand profiles as required for maximum utilization of renewable energy. Further, introducing a Time of Use (TOU) cost reflective tariff shall also encourage the customers to shift their demand to low cost periods, thus, reducing curtailments during daytime and preventing high cost generation during the night peak.

The detailed description of recommendations is provided in Chapter 14 of this report.

CHAPTER 1
INTRODUCTION

1.1 Background

Ceylon Electricity Board (CEB) is the state-owned electricity utility in Sri Lanka which is responsible for the generation, transmission, and distribution of electricity throughout the country and hence plays a crucial role in ensuring a reliable and efficient supply of electricity to meet the needs of residential, commercial, and industrial consumers.

In order to provide reliable and affordable electricity to the consumers it is required to proactively plan the developments to the transmission system and additions of new generation plants required to meet reasonable forecast demand. These requirements should be met at the least cost to the economy while assuring the technical feasibility and policy conformance. The Generation Planning Unit of CEB prepares the Long-Term Generation Expansion Plan (LTGEP) on behalf of the CEB to decide the most economical and technically realizable future generation mix of the country. Given the extended timeframe required for power sector projects, both generation and transmission, it is crucial to initiate and prioritize these development activities to meet the escalating demand for electricity and addressing the retirement of current generating assets. Hence LTGEP is prepared for a twenty-year horizon, and it is a rolling plan prepared biennially to capture the changes in the electricity sector and the country.

This report contains generation expansion planning studies carried out to decide the generation mix for the period 2025 – 2044 constrained by prevailing government policies and regulations. Planning studies have accounted for the forecasted electricity demand growth, candidate generating technologies most suitable to provide the capacity requirement, environmental and climate change considerations, operational characteristics of the future system, risk evaluation, and sensitivities to major changes such as fuel prices. A typical generation planning exercise strives to add a balance between three main competing objectives, as illustrated in Figure 1.1

a) The security and reliability of electricity supply
b) Sustainability
c) Economics of supply and affordability

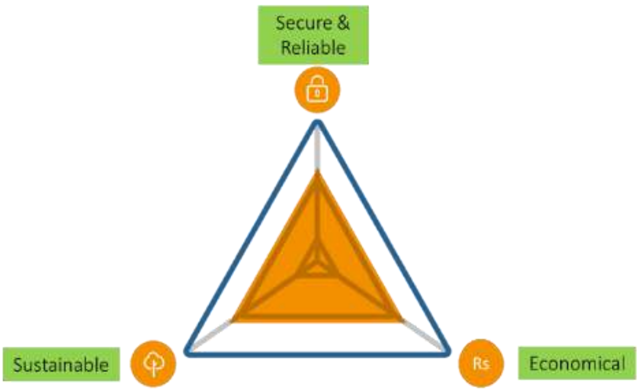


Figure 1.1 - Balance of Competing Objectives

Accordingly, this generation planning study was conducted to achieve a balance between above three objectives, constrained by legislative requirements imposed by the government.

The primary objectives of the generation planning studies conducted by CEB can be summarized into following,

a) Forecasting of 'National Long Term Electricity Demand' for the next 25 years
b) Investigating the techno economic feasibility of candidate generating technologies to expand the generating system.
c) Identifying the most appropriate generating capacity mix and required grid support interventions to meet the forecasted demand for electricity at lowest economic cost while meeting the reliability requirements and declared sector specific policies and regulations of the government as required under law.
d) Analysis of the operation of the proposed future system for each year of the study horizon
e) Preparing the capital investment program for the expansion of the generating system
f) Verifying the robustness of the economically optimum plan by analyzing its sensitivity to changes in the key input parameters.
g) Conducting scenario analysis to facilitate national level policy making.
h) Conducting contingency analysis to see possible risks in the near term.

The planning methodology, planning criteria and policy framework are explained in detail in chapter 7 of this report.

Note
The data presented in this report has been updated to January 2024 unless otherwise stated. Ongoing project information is updated to the latest information available by April 2024.

1.2 Economy of Sri Lanka

The Sri Lankan economy experienced a significant contraction due to the COVID-19 pandemic in 2020. Although there was a moderate recovery in 2021, mounting pressures on the exchange rate and the depletion of foreign reserves led to a severe economic crisis in 2022. This crisis saw the country's GDP shrink to historical lowest of -7.3%. In 2023, the GDP continued to decline, falling by an additional -2.3%. However, the Central Bank of Sri Lanka (CBSL) envisages that the economy will begin to recover by 2024, with a GDP growth rate of 3%. Yet in the present context, the expected recovery and future economic growth trajectory of the country is considerably uncertain.

Details of some demographic and economic indicators are given in Table 1.1 below.

1.2.1 Electricity and Economy

When analyzing historical data, it can be observed that there is an explicit relationship between the electricity demand growth rate and GDP growth rate. Variation of the GDP and demand growth rates over the years is depicted by Figure 1.2.

Table 1.1 - Demographic and Economic Indicators - Sri Lanka

	Units	2019	2020	2021	2022	2023
Mid-Year Population	Millions	21.8	21.9	22.2	22.2	22.0
Population Growth Rate	%	0.6	0.5	1.1	0.1	-0.6
GDP Growth Rate (Constant 2015 Prices)	%	-0.2	-4.6	4.2	-7.3	-2.3
GDP /Capita (Market Prices)	USD	4,082	3,851	3,999	3,464	3,830
Exchange Rate (Avg.)	LKR/USD	178.78	185.52	198.88	324.55	327.53
GDP (Constant 2015 Prices)	Mill LKR	13,206,276	12,595,550	13,125,505	12,161,201	11,881,736

Source: Annual Report 2022 [1] and Economic Review 2023 [2] by Central Bank of Sri Lanka

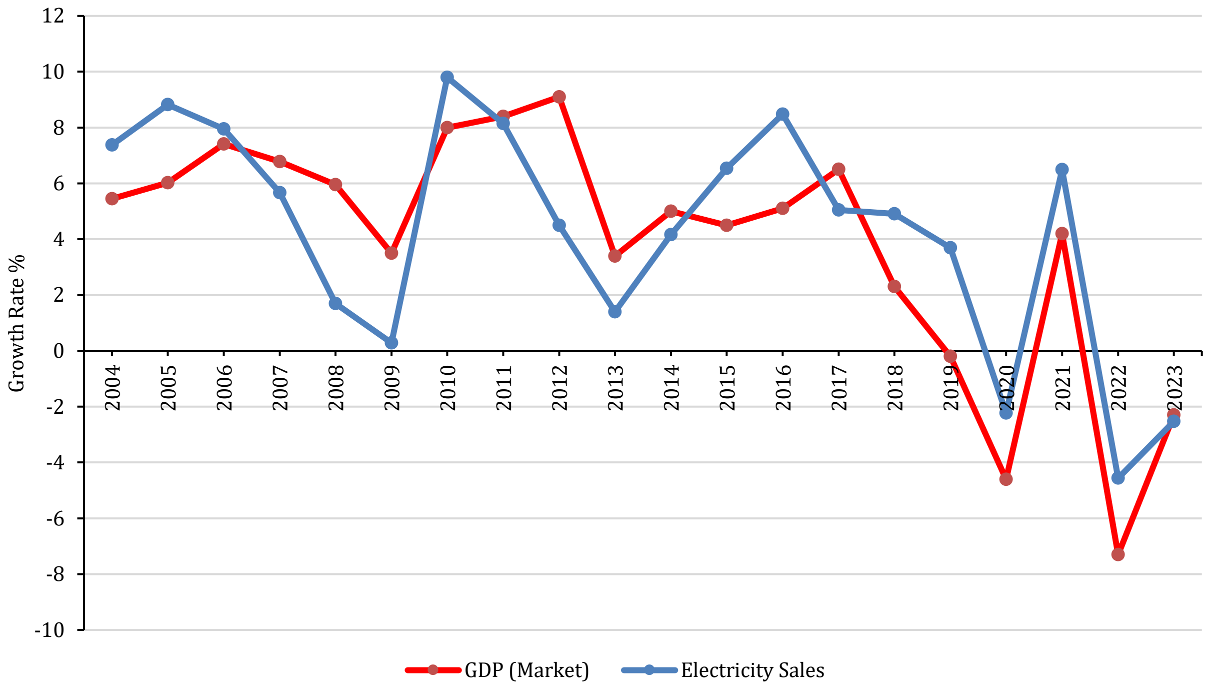


Figure 1.2 - Growth Rates of GDP and Electricity Sales

1.2.2 Economic Projections

Table 1.2 presents the GDP growth rates (%) in real terms for mid and near term as published by CBSL in their Annual Report 2021 [3], Annual Report 2022 and Economic Review 2023.

Table 1.2 - GDP Growth Rates Published by CBSL

Year	2022	2023	2024	2025	2026	2027
2021 Forecast	1.0					
2022 Forecast	-7.8	-2	3.3	4	4.5	5
2023 Forecast			3			

Source: Annual Report 2021, 2022 and Economic Review 2023 by Central Bank of Sri Lanka

1.3 Energy Sector of Sri Lanka

Overall energy requirement of the country is ensured through primary energy sources such as biomass (fuel wood) and coal, or by secondary sources such as electricity and refined petroleum products. The Energy Flow diagram of 2021 as published by the Sri Lankan Sustainable Energy Authority [4] is given in Figure 1.3. The energy flow diagram clearly shows the types of primary energy sources entered to the supply chain, their transition to secondary sources such as electricity and finished petroleum products at the middle and how they have ended up at different sectors of the economy.

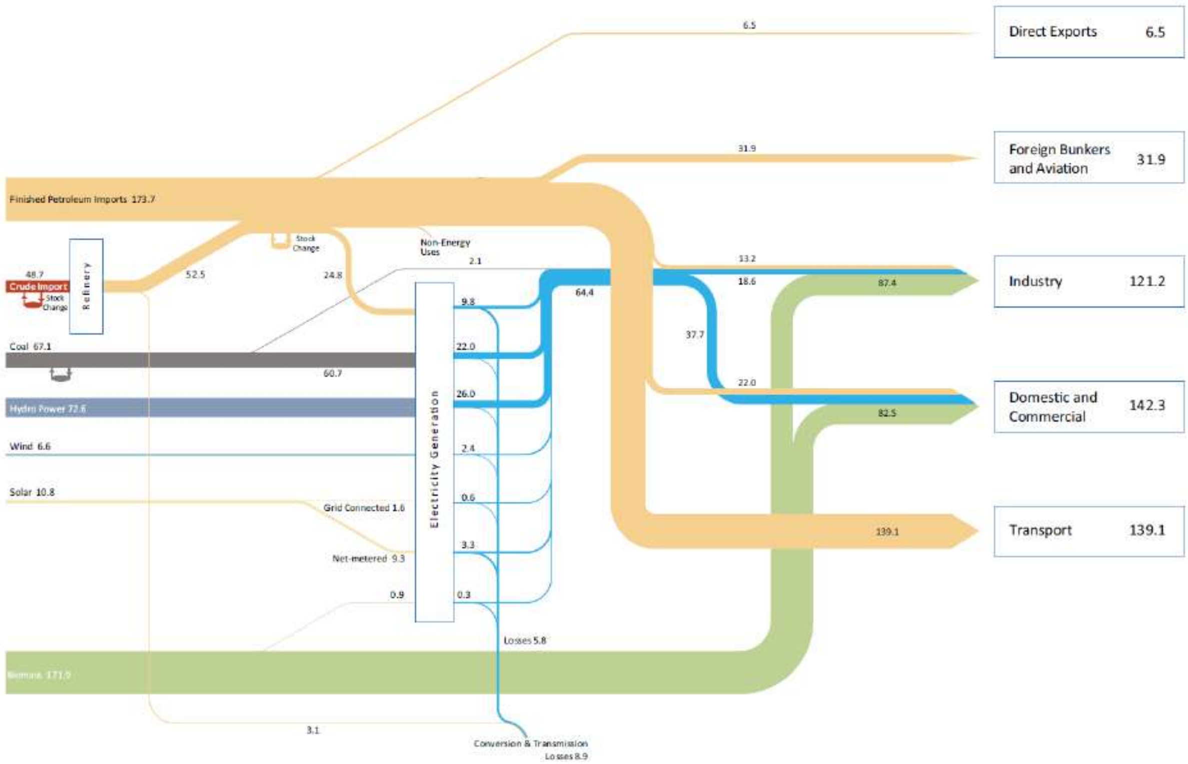


Figure 1.3 - Energy Flow Diagram (2021)

Source: Sri Lanka Energy Balance, Sri Lanka Sustainable Energy Authority

1.3.1 Energy Supply in Sri Lanka

Sri Lanka's primary energy supply relies on a mix of biomass, petroleum, coal, major hydro, and other renewable sources, with biomass and petroleum being the dominant contributors. As of the end of 2021, petroleum accounted for the largest share, covering approximately 38% of the energy supply. The country primarily obtains its petroleum through direct imports of finished products and refining imported crude oil, mainly at the Sapugaskanda refinery, which supplies about half of the country's petroleum needs. There are plans to expand the capacity of this refinery.

Primary energy supply of Sri Lanka by source from 2016 to 2021 in petajoule (PJ) is shown in Table 1.3 and percentage share of these sources from 2014 to 2021 is shown in Figure 1.4.

Table 1.3 - Primary Energy Supply (PJ) by Source

Year	2016	2017	2018	2019	2020	2021
Biomass	168.6	165.3	165.5	169.0	172.0	172.5
Petroleum	233.3	214.7	215.4	223.8	198.5	205.6
Coal	54.9	56.9	55.0	58.7	70.5	70.4
Major Hydro	35.0	30.9	51.9	38.2	39.5	56.9
New Renewable Energy	12.6	16.2	19.9	19.9	23.3	34.1

Source: Sri Lanka Energy Balance, Sri Lanka Sustainable Energy Authority

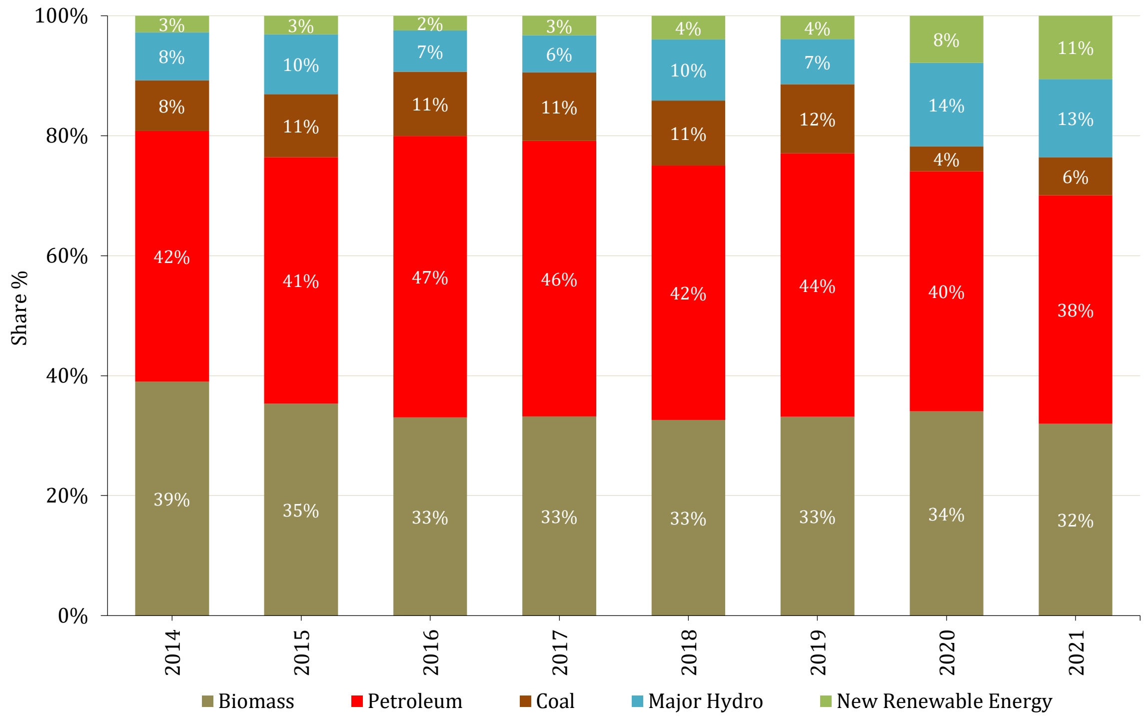


Figure 1.4 - Share of Primary Energy Supply by Source

Source: Sri Lanka Energy Balance, Sri Lanka Sustainable Energy Authority

Additionally, efforts have been made to explore oil in the Mannar Basin, off the north-west coast. Exploration licenses have been granted, and test wells have been drilled. Natural gas has been discovered in the Mannar Basin, offshore from the Kalpitiya Peninsula, with an estimated discoverable gas amount of approximately 350 billion cubic feet (bcf) and a potential extraction rate of 70 million standard cubic feet per day (mscfd). Further exploration is needed to verify these figures, but there's potential for the reserves to extend beyond 1.8 trillion cubic feet (tcf) with extraction rates of up to 100 mscfd.

Biomass, primarily fuel wood used non-commercially, contributed approximately 32% of the total energy supply. However, even it is the most abundant energy source in the country, due to its predominantly non-commercial use, only a limited portion of biomass is traded in the commodity market, resulting in an undervaluation of the energy sourced by biomass.

Coal, primarily imported for electricity generation, represented 13% of the primary energy supply in 2021. Hydro power, on the other hand, accounted for 10.5%, making it the primary indigenous source of commercial energy. Despite its significant potential, further exploitation of hydro resources faces challenges due to social and environmental impacts associated with large-scale development. Nonetheless, hydro remains a crucial component of Sri Lanka's energy mix.

Other renewable energy sources, including wind, solar, and small hydro, collectively contributed 6.3% to the total energy supply in 2021. The country has substantial potential for wind and solar power development, with initiatives already underway to optimize their utilization. Commercial wind power plants were first established in 2010, with a total capacity reaching 267 MW by the end of 2023. The first large scale wind farm was commissioned in Mannar island in 2020. Similarly, commercial solar power plants began operating in 2016, with a cumulative capacity of 953 MW by 2023, along with approximately 815 MW from rooftop solar plants. Scattered developments of small-scale solar power plants have been already initiated and feasibility studies were initiated to develop solar power plants in park concept. A minor portion of the biomass supply is used for power generation thorough dendro, agricultural waste and municipal waste sources.

1.3.2 Energy Demand in Sri Lanka

The energy demand in Sri Lanka is categorized into biomass, petroleum, electricity, and coal. The primary use of biomass is in the domestic sector, mainly for cooking purposes. The country's total fossil fuel requirement encompasses transportation, power generation, industrial, and other applications. Prior to the commissioning of the coal power plant in Norochcholai, coal demand was primarily for the industrial sector. However, since the commissioning of coal power plants in Norochcholai, 96% of total coal imports have been allocated to electricity generation.

Table 1.4 illustrates the recent energy demand breakdown by each energy source. In biomass, petroleum, and coal categories their usage in electricity generation is excluded. Further percentage share of the sources is shown in Figure 1.5.

Table 1.4 - Energy Demand (PJ) by Source

Year	2016	2017	2018	2019	2020	2021
Biomass	166.7	163.4	163.1	165.8	169.3	169.9
Petroleum	183.2	172.1	170.0	174.3	154.8	177.9
Coal	2.1	1.8	2.0	2.3	2.1	2.1
Electricity	45.8	48.3	50.8	53.2	52.0	55.6

Source: Sri Lanka Energy Balance, Sri Lanka Sustainable Energy Authority

The main consumption sectors of energy demand can be categorized into industry, transport, household and commercial sectors. The sectorial energy consumption trend from 2011 to 2021 is shown in Figure 1.6. Till 2020, the household and commercial sector appear to be the largest sector in terms of energy consumption while the transport sector is the second largest followed by the industry sector which has the minimum share of consumption. However, in 2021 both household and commercial sector and transport sector share the same percentage of 35%. It can be observed that the household and commercial sector exhibits a decreasing trend while both transport and industrial sectors show an increasing trend.

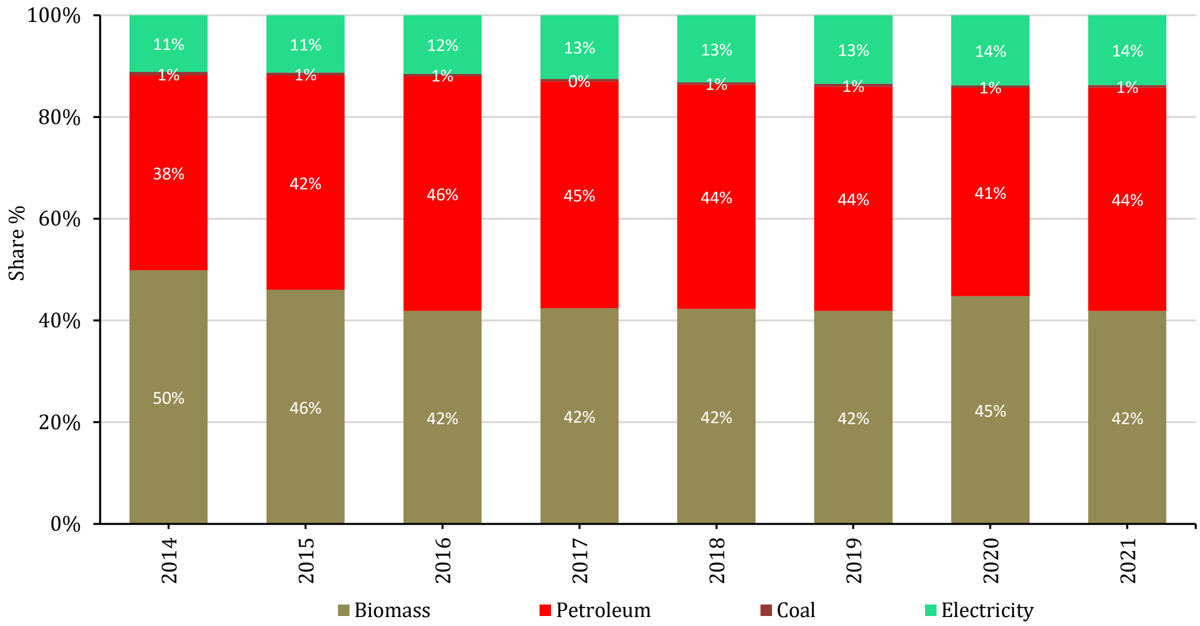


Figure 1.5 - Share of Energy Demand by Source

Source: Sri Lanka Energy Balance, Sri Lanka Sustainable Energy Authority

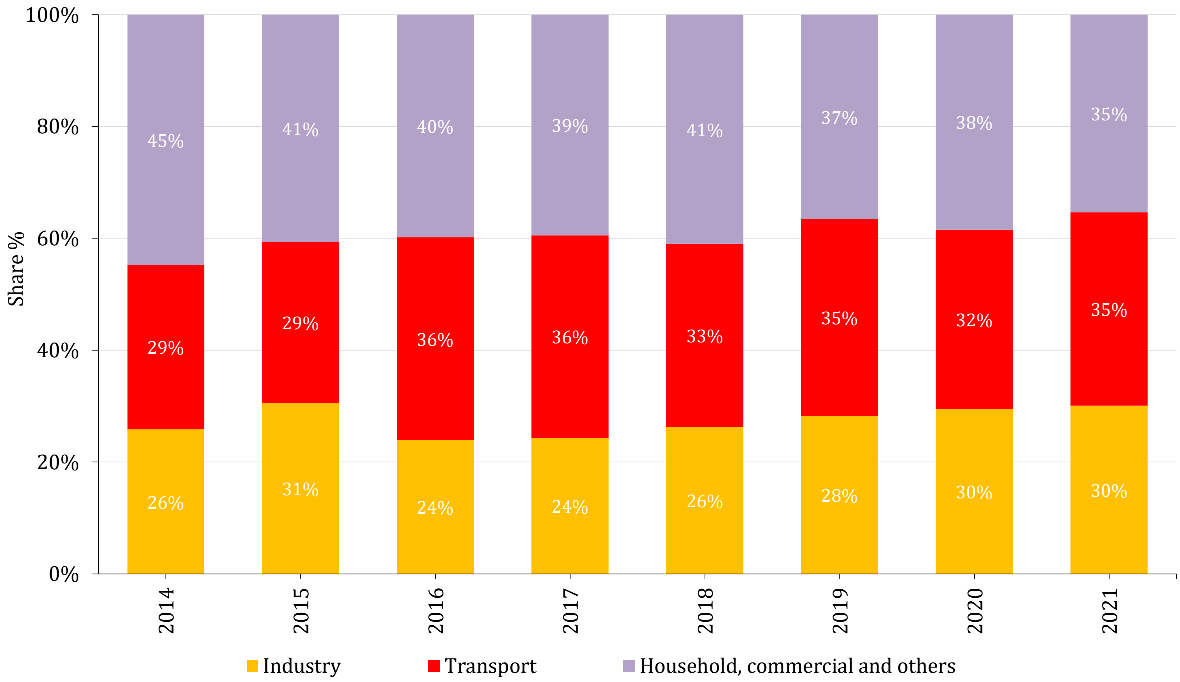


Figure 1.6 - Energy Demand by Sector

Source: Sri Lanka Energy Balance, Sri Lanka Sustainable Energy Authority

1.4 Electricity Sector

1.4.1 Global Electricity Sector

The global demand for electricity has seen consistent growth, averaging around 3% annually over the past twenty years [5]. During this period, fossil fuel-based thermal generation has predominantly met the world's electricity needs. Similarly, in 2022, only 38% of the world's electricity was delivered by carbon-free generation sources while the remaining accounted for fossil energy. However, there has been a notable expansion in renewable energy sources, particularly driven by the increasing utilization of solar PV and wind resources, alongside moderate growth in mini-hydro and biomass generation.

Despite the global energy crisis sparked by Russia's invasion of Ukraine, world electricity demand demonstrated resilience in 2022 experiencing nearly a 2% increase compared to the average 2.4% growth rate observed during the period of 2015-2019. This growth was driven by the continued expansion of electrification in the transportation and heating sectors globally, marked by record-breaking sales of electric vehicles and heat pumps throughout the year. However, economies worldwide, still in the process of recovering from the impacts of the Covid-19 pandemic, faced significant challenges due to record-high energy prices due to steep rise in prices for energy commodities like natural gas and coal during 2022 which in turn hindered the growth of electricity demand in most regions across the globe except India and USA.

The surge in fossil fuel prices following Russia's invasion of Ukraine resulted in relatively higher increase in natural gas and LNG prices. This prompted a wave of fuel switching in the world to coal increasing global coal-fired generation by 1.5% in 2022. Global gas-fired generation remained relatively unchanged in 2022 compared to 2021, as declines in China, India and other regions were largely offset by a rise in gas-fired output in the United States.

In 2022, low-carbon generation from renewables and nuclear energy exhibited contrasting trends. Power systems encountered challenges across various regions, including Europe, China, and the USA, due to extreme weather events such as heatwaves and droughts. These events led to an approximate 7% decrease in hydropower output compared to the previous year. Despite these challenges, renewables experienced a year-on-year increase of 5.7%, accounting for nearly 30% of the overall generation mix. The Asia Pacific region witnessed a significant surge in renewable generation, contributing to over half of the total increase, followed by the Americas. In contrast, nuclear output declined by 4.3% due to maintenance outages at numerous French plants, the decommissioning of units in Germany and Belgium, and reduced output from Ukraine.

In 2022, the global installed capacity of renewables is estimated to have expanded at a faster year-on-year rate of nearly 11%, surpassing the average 9% growth observed during the period from 2017 to 2021. Variable renewables, namely wind and solar PV, continued to experience robust growth in combined capacity, increasing by almost 18%. Despite this ongoing expansion, the proportion of variable renewable capacity within the total generation fleet worldwide remains below 25%.

When considering world electricity source mix of 2022 [6], coal has been world's main source of electricity, generating 36% of the total electricity supply while fossil gas supplied 22% followed by

15% supplied by hydro. Nuclear power generated 9.2% of the electricity supply and solar photovoltaics and wind turbines generated 4.5% and 7.3% respectively.

With the increasing share of variable renewable sources in electricity systems worldwide, the deployment of stationary battery systems is accelerating. The United States, Europe, and China are at the forefront of the latest annual capacity additions, while emerging markets and developing economies are rapidly catching up. Compared to 2021, capacity additions in 2022 surged by over 80% in the United States, nearly 100% in China, approximately 35% in Europe, and 90% in OECD Pacific countries, which include Japan, Korea, Australia, and New Zealand.

In 2022, global CO_2 emissions from electricity generation experienced a growth rate comparable to the average observed between 2016 and 2019. The increase of 1.3% in 2022 marked a significant deceleration from the substantial 6% rise witnessed in 2021, which was primarily fueled by the rapid economic rebound following the Covid shock. However, despite this slowdown, CO_2 emissions related to electricity generation reached an all-time high in 2022 to 13.2 Gt CO_2. This is mainly due to growth in fossil-fired generation in Asia Pacific.

World electricity generation by source from 2003 to 2022 is shown in Figure 1.7 and its percentage wise representation from 2008 to 2022 is presented in Figure 1.8.

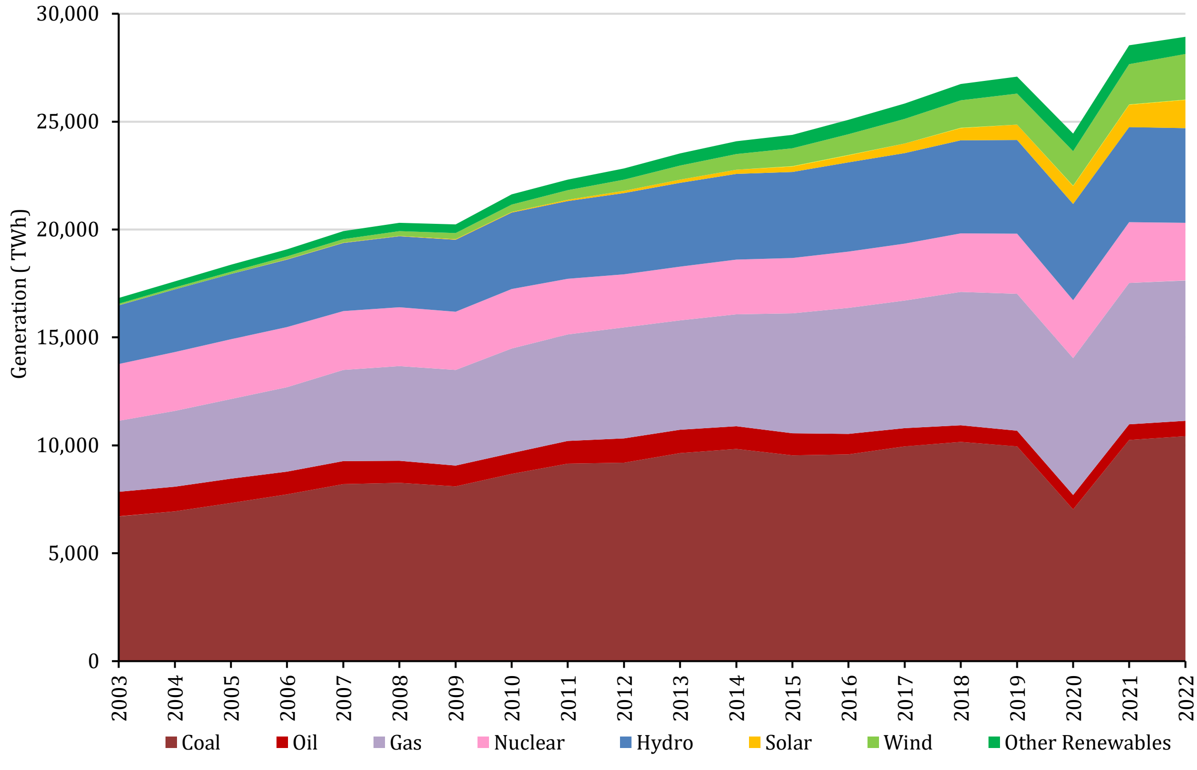
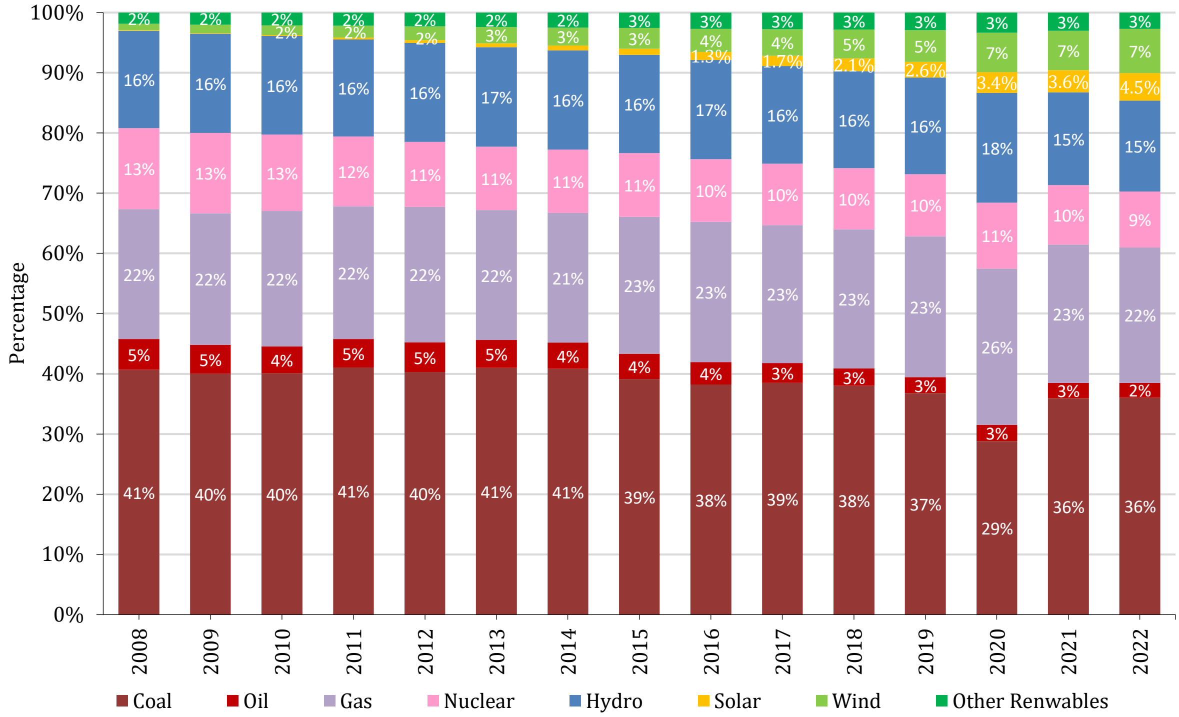


Figure 1.7 - World Electricity Generation by Source

Source : International Energy Agency Statistics



Source : International Energy Agency Statistics

Figure 1.8 - World Electricity Generation by Source as Percentage

1.4.2 Sri Lankan Electricity Sector

1.4.2.1 Overview

The electricity sector in Sri Lanka plays a crucial role in powering the country's economy and meeting the energy needs of its population. Electricity sector serves around 14% of the total energy demand in Sri Lanka. It has undergone significant development and transformation over the years, characterized by a mix of traditional thermal and hydro power generation to a growing emphasis on other renewable energy sources.

In Sri Lanka, the electricity market is primarily dominated by the domestic sector, which holds a 36% market share. Meanwhile, the industrial and commercial sectors have fairly equal segments. Over the past few years, electricity demand has experienced significant fluctuations in growth rates compared to historical trends. Specifically, there were negative growth rates in 2020, 2022, and 2023, attributed to the COVID-19 pandemic and the subsequent Sri Lankan economic recession. Additionally, major planned load shedding occurred in 2022. As a result, the 5-year average growth rate of electricity demand from 2019 to 2023 stands at -0.8%.

The maximum recorded peak demand of 2,415 MW occurred in March 2023. Total net electricity generation in 2023 was 15,728 GWh (including rooftop solar export of CEB & LECO consumers). Both the recorded peak and net generation are substantially lower than the pre-economic crisis levels.

At the end of 2023, Sri Lanka had a total installed generating capacity, including rooftop solar, of (approximately) 5,194 MW. This included 3,107 MW of renewable energy based generating capacity and 2,088 MW of thermal capacity.

Thermal power plants, which are dispatchable plants, are fueled by oil and coal and the fleet currently includes reciprocating engines, open cycle and combined cycle turbines and steam plants. It is expected to introduce Liquid Natural Gas (LNG) to the fuel mix in the near future while phasing out oil to align with the national clean energy obligations. Renewable plants are mainly based on hydro, solar, wind and biomass sources. The major hydro power plants are dispatchable but with constraints due to hydrological conditions and multipurpose usages while other renewable energy plants are inherently non dispatchable in nature. At present the total dispatchable generation capacity is 3,501 MW while the balance of 1,693 MW from ORE is non dispatchable.

It is anticipated to drive further diversification of the fuel sources with the significant increase of integrating renewable energy and this transition is expected to entail a substantial move away from reliance on imported commercial fuels towards utilizing indigenous resources for power generation.

1.4.2.2 Access to Electricity

The electricity network in Sri Lanka spans the entire country, providing electricity access to nearly all citizens. Notably, efforts to improve efficiency have led to a decrease in transmission and distribution losses from 21.4% in 2000 to 8.72% in 2023.

Sri Lankan high voltage network consists of 220 kV and 132 kV voltage levels which are of 998 km and 2,405 km in length respectively whereas 33 kV and 11 kV distribution network of CEB is 44, 361 km in length. Electricity is distributed to the low voltage network through 37,095 grid, primary and distribution substations.

The electricity demand is projected to rebound to pre-economic crisis levels in the near future and it will eventually continue rising. Additionally, to accommodate the anticipated higher share of renewable energy, network improvements are essential. Hence the continuous expansion of the network is a necessity. This involves ongoing improvements to grid substations and transmission capacity, as well as the installation of new generating capacity to meet the increasing electricity requirements along with adequate advances in the distribution network.

1.4.2.3 Electricity Consumption

The sectorial electricity consumption of the past twenty years is shown in Figure 1.9. Figure 1.10 illustrates the share of sectorial electricity consumption in 2023.

Until the Covid 19 pandemic break out in 2020 diminished the electricity sales, there was a continuous electricity demand growth during the last two decades. Even though the demand bounced back in 2021 it was again affected by the economic downturn the country faced during 2022 along with the substantial planned load shedding. This decline in the sales further deteriorated in 2023 with the persistent challenges on economy. Total sales in 2023 were 14, 195 GWh exhibiting a reduction of 2.3% compared to 2022 sales levels. Commercial and Industrial sector sales has diminished in 2023 by 0.4% and 3% respectively while domestic sales have increased by 3% compared to 2022 figures.

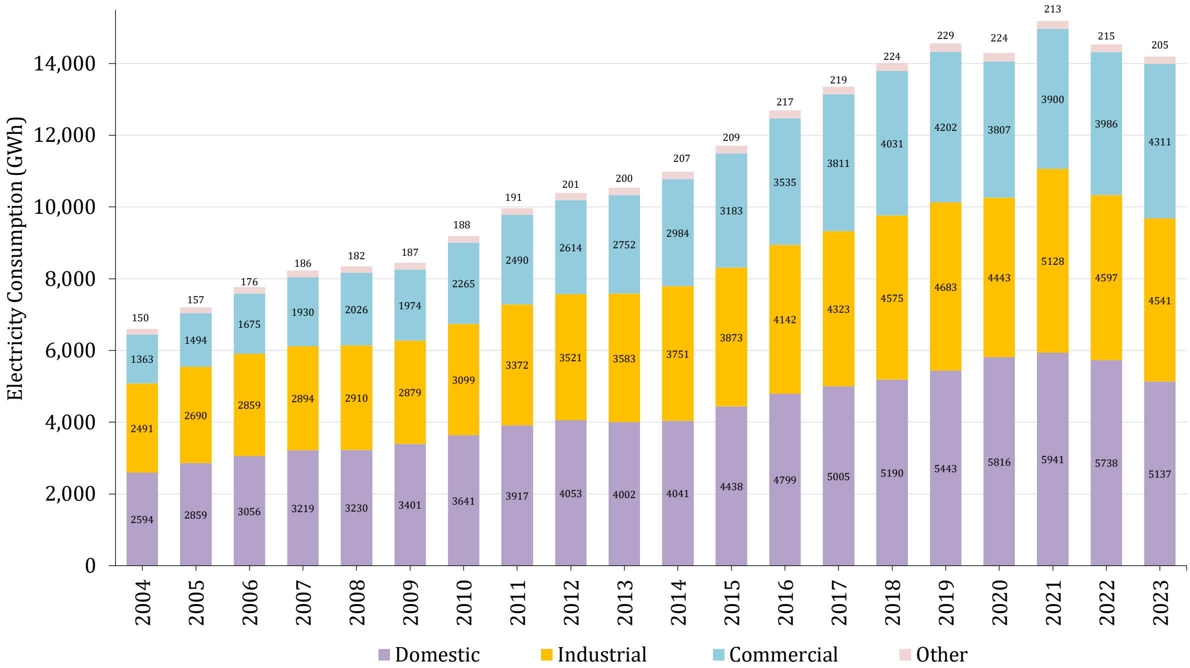


Figure 1.9 - Sectorial Consumption of Electricity

Note
Commercial sector includes general purpose, hotel, and government tariff categories.
Other sector includes religious purpose, street lighting, agriculture (from 2021 onwards) and temporary tariff categories.

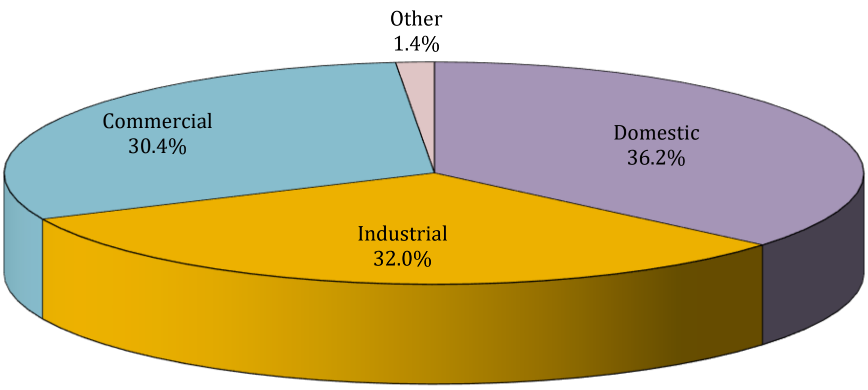


Figure 1.10 - Sectorial Consumption of Electricity (2023)

When considering the sectorial consumption share of 2023, domestic sector still is the prominent sector with approximately 36% share. Industrial and commercial sector accounts for 32% and 30% share respectively. Commercial market share, which was rapidly growing for past decade, reduced post the Covid-19 out break between 2020 to 2022. It has regained its market share in 2023 while domestic share has decreased to pre-covid levels. Industrial share has reached pre-covid market share again in 2023.

The average per capita electricity consumption has a generally increasing trend during the past two decades up to 2019. There was a drop in the per capita consumption due to COVID 19 break out in 2020 and similarly in year 2022, after the economic recession. This further reduced by 2% in 2023 to 642 kWh/person.

Figure 1.11 illustrates the variation of per capita electricity consumption of Sri Lanka between 2003 to 2023.

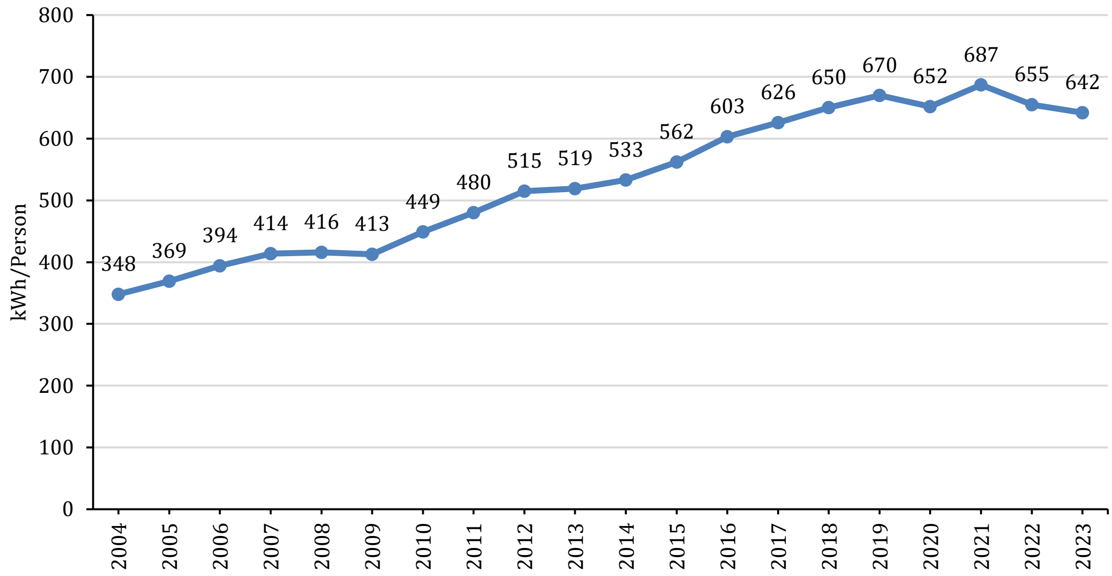


Figure 1.11 - Per Capita Electricity Consumption in Sri Lanka

1.4.2.4 Cost of Electricity

Affordable electricity is crucial for every aspect of society including households, businesses, and industries. Electricity is a key factor which decides the standard of living for households while for businesses and industries electricity is a key driver for operational efficiency and cost effectiveness. Hence affordable electricity plays a vital role in the overall economic development of a country.

In order to keep the electricity prices low, it is mandatory to keep the electricity generating cost low and effectively manage the transmission and distribution infrastructure. On the other hand the electricity tariff has to be cost reflective in order to send correct price signals to customers which in turn manage the demand accordingly.

Both the fixed cost and the variable cost of producing and supplying a unit of electricity and losses decide the final cost of electricity supplied at end user level. The fixed cost component consists of the fixed cost of generation plants, the costs pertaining to transmission and distribution of electricity, while the variable cost component is mainly determined by the cost of fuel used for thermal generation and variable energy charge paid to renewable sources. Due to different weather conditions which affects renewable energy production including variations in hydrology, irradiation and wind speed and fuel price fluctuations caused by economic factors, cost of generating a unit of electricity could significantly vary from one instance to another.

To combat these variations in the renewable power generation, grid interventions are needed which involves high capital investment. Generation planning studies are carried out to find the most economical technology mix under various hydrological conditions occurring in different probabilities with varying renewable resource profiles.

Figure 1.12 illustrates how the actual cost of electricity (at selling point) has changed from year 2014 to 2023.

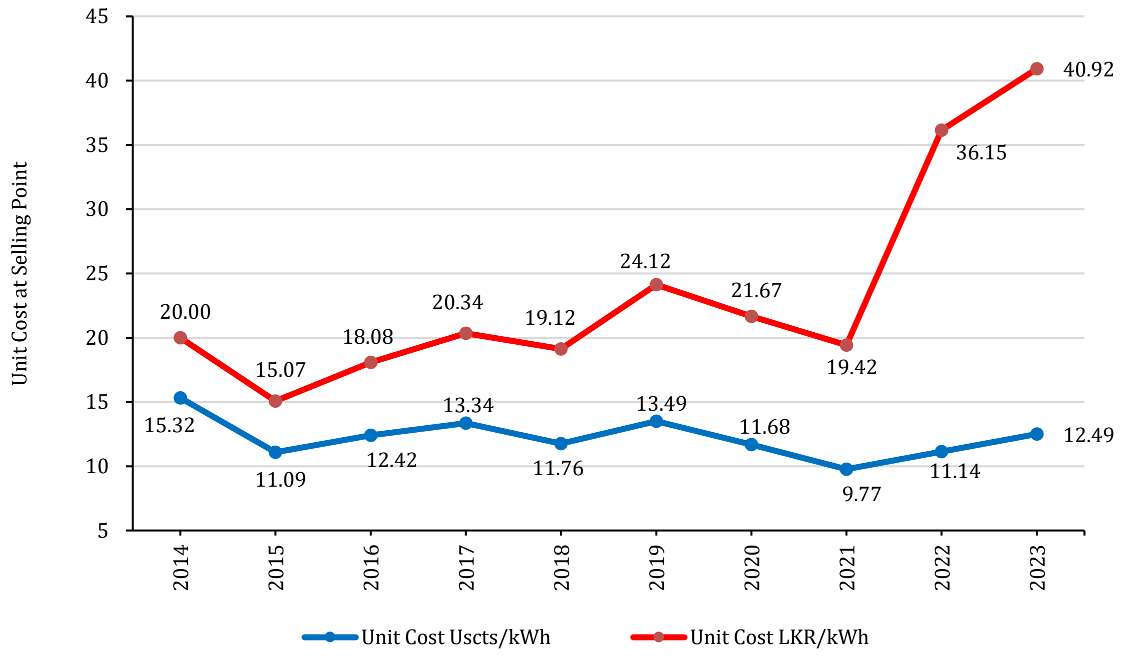


Figure 1.12 - Average Cost per Unit (at the Selling Point)

1.4.2.5 Electricity Demand and Supply

Sri Lankan daily electricity demand profile has three distinguishable periods classified as the night peak, day peak and off peak. Though the night peak records the highest electricity demand at present, the day time demand is expected to become prominent in years to come. During 2015 to 2021 system peak demand has been growing at an average rate of 3.5%, however in 2022 there is a dip of 3% in the peak demand and it further deteriorated in 2023 indicating the contraction of the economy to 2,415 MW which was over a 10% reduction even compared to 2022 peak demand.

The total installed capacity consists of both dispatchable and non dispatchable forms of generation sources. Ensuring adequate dispatchable capacity is important with the growing peak demand and the firm capacity shortfalls experienced in dry hydrological conditions. By the end of 2023, the total installed capacity was 5,194 MW including non dispatchable power plants (small hydro, wind, solar and biomass).

Table 1.5 portrays historical installed capacity and peak demand of Sri Lankan electricity system for past 20 years.

Table 1.5 - Installed Capacity and Peak Demand

Year	Installed Capacity[1] (MW)	Capacity Growth (%)	Peak Demand (MW)	Peak Demand Growth (%)
2004	2,280	4.4	1,563	3.1
2005	2,411	5.4	1,748	11.8
2006	2,434	0.9	1,893	8.3
2007	2,444	0.4	1,842	-2.7
2008	2,645	7.6	1,922	4.3
2009	2,684	1.5	1,868	-2.8
2010	2,818	4.8	1,955	4.7
2011	3,141	10.3	2,163	10.6
2012	3,312	5.2	2,146	-0.8
2013	3,359	1.4	2,164	0.8
2014	3,946	17.5	2,152	-0.6
2015	3,875	-1.8	2,283	6.1
2016	4,079	5.2	2,453	7.4
2017	4,136	1.4	2,523	2.9
2018	4,215	1.9	2,616	3.7
2019	4,497	6.7	2,669	2.0
2020	4,617	2.7	2,717	1.8
2021	4,701	1.8	2,802	3.1
2022	4,907	4.4	2,708	-3.4
2023	5,194	5.9	2,415	-10.8
Last 5-year Average Growth		3.67		-2.47
Last 10-year Average Growth		3.10		1.29
Last 20-year Average Growth		4.43		2.32

[1] Rooftop solar capacity additions of CEB & LECO customers are considered from 2013.

Figure 1.13 shows the total installed capacity and peak demand of the system since 2004 to 2023.

The Figure 1.14 illustrates the past development of other renewable energy sources including mini hydro, wind, solar PV and biomass. Solar PV has been the primary driver of capacity growth in recent years, with wind capacities following closely behind. Moderate growth has been recorded in mini-hydro and biomass capacities.

Electricity generation of the country was predominantly 100% from hydropower until mid-nineties. However, with the growth in electricity demand during the last 20 years and the limited potential to develop new large hydropower resources, the power generation mix in the country has shifted to a mixed hydro-thermal system. Relatively high share of oil based power generation still exists in the present generation mix due to the growing demand, hydrological variations and delays in implementing other major power projects which has a significant impact on the cost of generation.

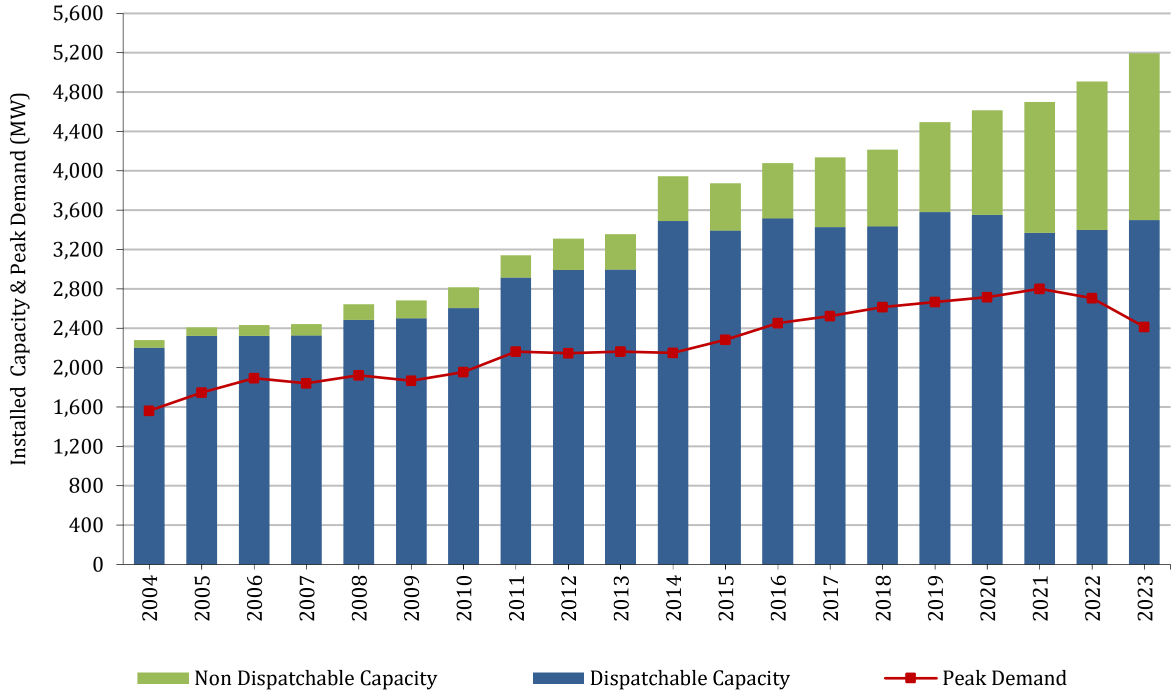


Figure 1.13 - Total Installed Capacity and Peak Demand

Note
Rooftop solar capacity additions of CEB & LECO customers are included in non-dispatchable capacity from 2013

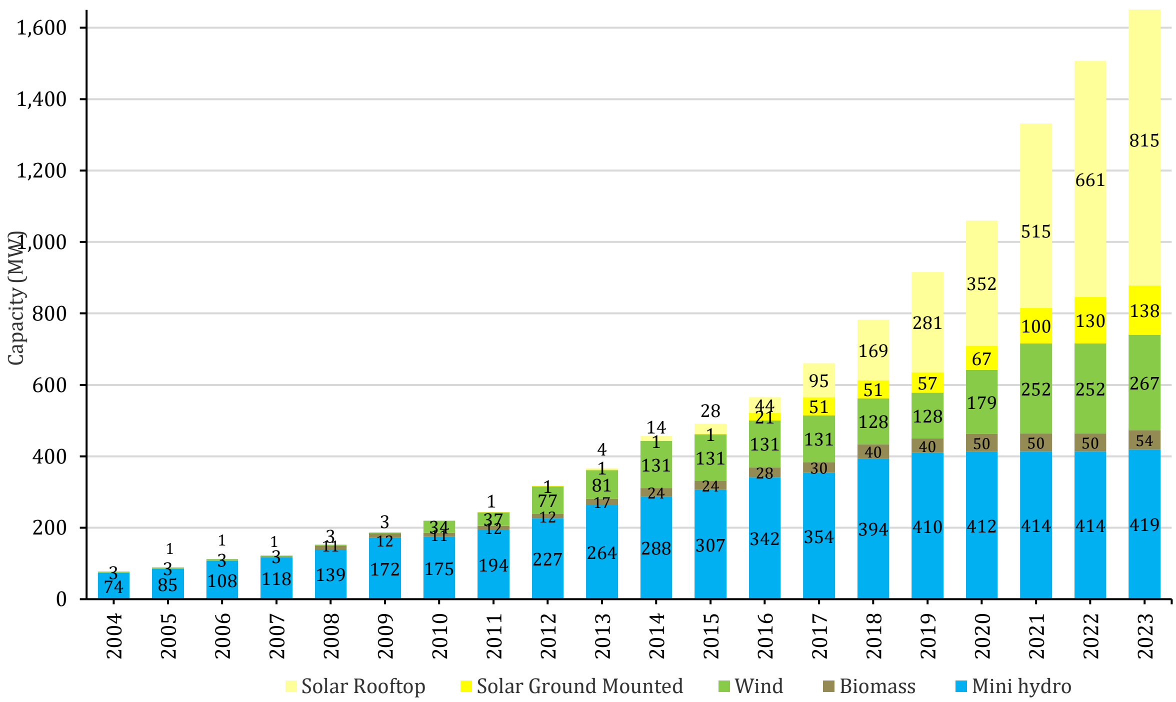


Figure 1.14 - Other Renewable Energy Capacity Development

In the year 2023, nearly 49% of the generation came from fuel based sources including 30% of the share from coal based generation. The remaining 51% came from renewable energy based generation from which 29% contribution is from major hydro power plants. Electricity Generation during the last twenty-five years is summarized in Table 1.6 and illustrated in Figure 1.15. Sri Lankan electricity system has been maintaining the total renewable energy share between 30% - 60% during the recent past. Major Hydro contribution has varied notably depending on the hydrological conditions and the other renewable energy share has been increasing steadily. The total renewable energy share of the past fifteen years is shown in Figure 1.16.

Table 1.6 - Electricity Generation

Year	Hydro Generation		Other Renewable[1]		Thermal Generation		Self-Generation		Total
	GWh	**%**	**GWh**	**%**	**GWh**	**%**	**GWh**	**%**	**GWh**
1999	4,135	67.5	21	0.3	1,871	30.6	97.0	1.6	6,125
2000	3,138	46.3	46	0.7	3,437	50.7	158.0	2.3	6,780
2001	3,030	46.2	68	1.0	3,361	51.2	105.0	1.6	6,564
2002	2,575	37.4	107	1.6	4,074	59.1	136.0	2.0	6,892
2003	3,175	42.0	124	1.6	4,263	56.4	0	0.0	7,562
2004	2,739	33.8	208	2.6	5,051	62.3	115.0	1.4	8,113
2005	3,158	36.3	282	3.2	5,269	60.5	0	0.0	8,709
2006	4,272	45.9	349	3.7	4,694	50.4	0	0.0	9,314
2007	3,585	36.8	347	3.6	5,800	59.6	0	0.0	9,733
2008	3,683	37.5	438	4.5	5,697	58.0	0	0.0	9,819
2009	3,338	34.0	552	5.6	5,914	60.3	0	0.0	9,803
2010	4,969	46.7	731	6.9	4,948	46.5	0	0.0	10,649
2011	3,999	35.2	725	6.4	6,629	58.4	2.9	0.0	11,356
2012	2,710	23.1	736	6.3	8,280	70.6	1.4	0.0	11,727
2013	5,990	50.3	1179	9.9	4,729	39.7	0	0.0	11,898
2014	3,632	29.5	1217	9.9	7,466	60.6	0	0.0	12,316
2015	4,904	37.5	1467	11.2	6,718	51.3	0	0.0	13,090
2016	3,481	24.6	1160	8.2	9,507	67.2	0	0.0	14,148
2017	3,059	20.8	1464	10.0	10,148	69.2	0	0.0	14,671
2018	5,149	33.5	1832	11.9	8,390	54.6	2.4	0.0	15,374
2019	3,784	23.7	1806	11.3	10,378	64.9	14.2	0.1	15,982
2020	3,911	24.8	1931	12.2	9,936	63.0	1.6	0.0	15,780
2021	5,640	33.6	3005	17.9	8,153	48.5	0	0.0	16,798
2022	5,364	33.4	3050	19.0	7,642	47.6	4.1	0.0	16,060
2023	4,573	29.1	3374	21.5	7,780	49.5	0	0.0	15,728
Last 5 year Avg. Growth				16.90		-6.95			-0.40
Last 10 year Avg. Growth				11.99		0.46			2.75
Last 20 year Avg. Growth				15.79		2.30			3.55

[1]Solar rooftop export from CEB & LECO consumers are considered from 2019 onwards and self-consumption of such plants are excluded.

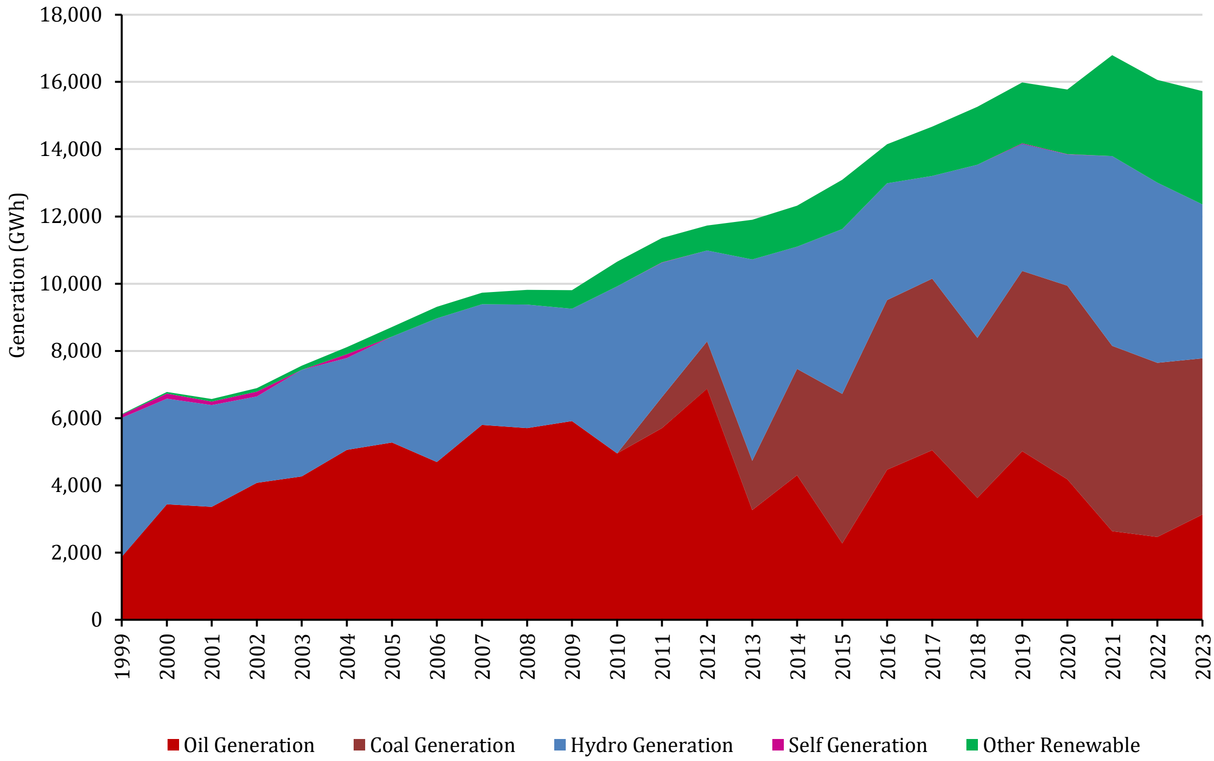


Figure 1.15 - Generation Share in the Recent Past

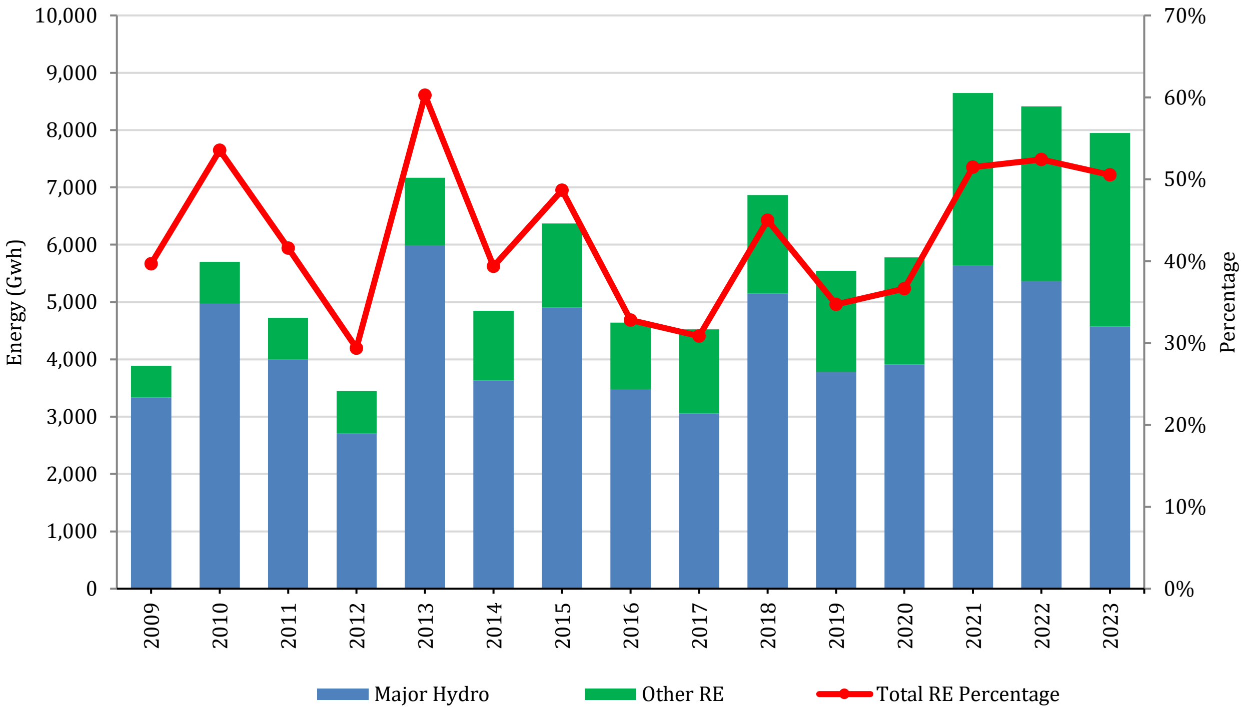


Figure 1.16 - Renewable Share in the Recent Past

1.5 Emissions

The total global Green House Gas (GHG) emissions from fuel combustion was 34,981.2 $MtCO_2eq$ in 2022 while Sri Lankan emission level was just 20.9 $MtCO_2eq$ which accounts only for 0.1% of the global emissions. The absolute emission levels as well as the per capita emission levels of Sri Lanka remains low compared to the overall global average. Emission levels comparison with many regional countries, countries having similar economies and that of developed countries are shown in Table 1.7.

Table 1.7 - Comparison of Emissions from Fuel Combustion (2022)

Country	**Total GHG Emissions - Fuel Combustion ($MtCO_2eq$)**	**CO_2 Emissions per Total Energy Supply (tCO_2/TJ)**	**CO_2 Emissions per Unit of GDP (PPP) ($kgCO_2$/2015 USD)**	**CO2 Emissions per Population (tCO_2/capita)**
Sri Lanka	**20.9**	**41.7**	**0.1**	**0.8**
Pakistan	232.6	41.9	0.2	0.9
India	2,651.9	59.2	0.2	1.8
Bangladesh	112.8	49.3	0.1	0.6
Indonesia	663.3	59.7	0.2	2.4
Malaysia	243.3	57.9	0.3	7.1
Thailand	255.9	44.8	0.2	3.5
China	10,750.8	66.7	0.4	7.5
Japan	982.5	59.3	0.2	7.8
France	289.6	32	0.1	4.1
Denmark	27.7	41.2	0.1	4.5
Germany	621.7	53.9	0.1	7.3
Switzerland	32.7	33.4	0.1	3.6
United Kingdom	314.1	48.3	0.1	4.6
Russia	1,635.1	48	0.4	11.3
USA	4,677.8	50.6	0.2	13.8
Canada	530.4	42.1	0.3	13.4
Australia	358.6	66.6	0.3	13.6
South Africa	398.8	76.3	0.5	6.6
Qatar	91	48.8	0.4	33.6
Egypt	220.2	51.3	0.1	2
Brazil	439.2	32.9	0.1	1.9
World	34,981.2	54.8	0.2	4.3

Source: International Energy Agency Statistics

Globally, electricity sector is the major contributor of CO_2 emissions out of the total energy use or fuel combustion. However, in Sri Lanka, the transport sector is the largest contributor to emissions whereas electricity sector becomes the second. Contributions to CO_2 emissions of Sri Lanka in the recent past is tabulated in Table 1.8 and sector wise comparison of CO_2 emissions of Sri Lanka and the world in 2022 is shown graphically in Figure 1.17 & 1.18.

Table 1.8 - Sri Lanka CO2 Emissions in the Recent Past

Year	Overall CO_2 Emissions ($MtCO_2$)	Electricity Sector CO_2 Emissions ($MtCO_2$)
2013	13.7	4.0
2014	16.7	6.8
2015	19.5	6.7
2016	20.9	8.6
2017	23.1	9.4
2018	20.6	8.1
2019	22.5	9.7
2020	20.8	9.4
2021	21.1	8.3
2022	18.4	7.7

Source: International Energy Agency Statistics

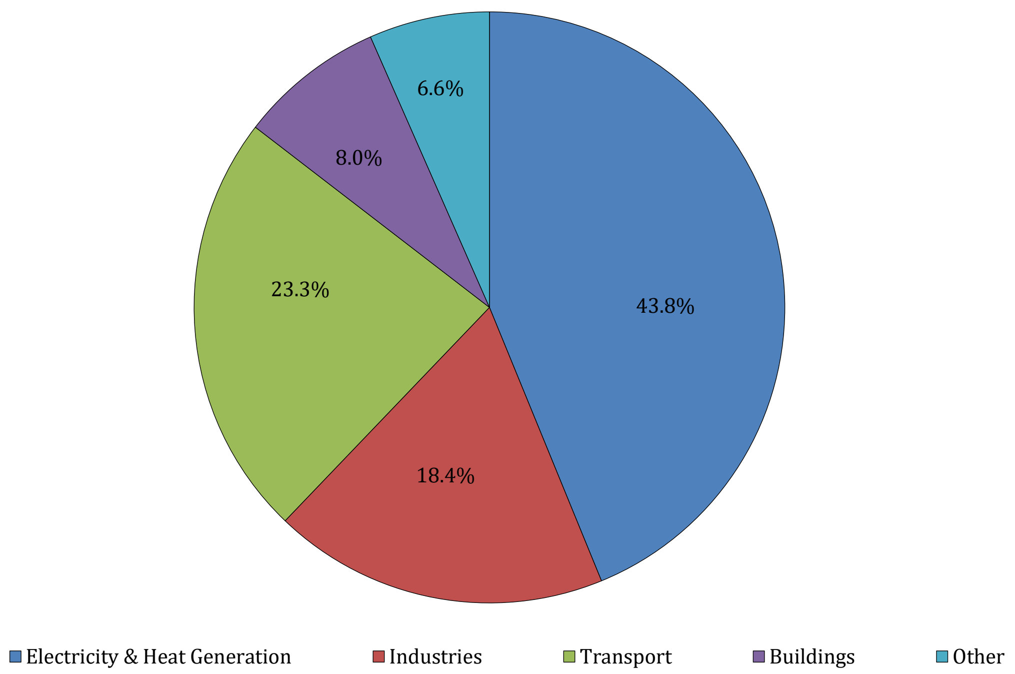


Figure 1.17 - CO_2 Emissions from Fuel Combustion 2022 – World

Source: International Energy Agency Statistics

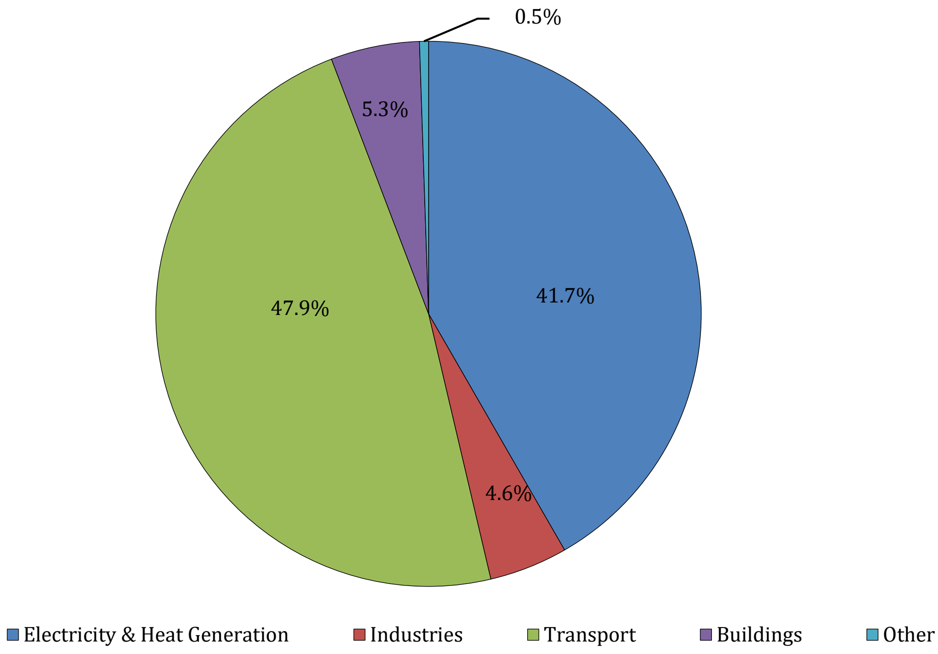


Figure 1.18 - CO2 Emissions from Fuel Combustion 2022 – Sri Lanka

Source: International Energy Agency Statistics

1.6 Implementation of the Expansion Plan

After preparation of LTGEP, it is submitted for necessary approvals and once the approvals are granted it becomes a legally binding document which outlines the guideline for generation infrastructure development for future years until a successive plan is approved. Subsequently a corresponding Long Term Transmission Development Plan (LTTDP) is prepared for facilitating the transmission infrastructure development for the anticipated generation expansions.

As both the power plant projects and transmission development projects need lengthy lead times and substantial investments plus the preparation of a LTGEP itself takes more than ten months, it is important to have timely approved plans to ensure a consistent development in the electricity sector.

The latest approved plan is LTGEP 2023 -2042 which received PUCSL approval in February 2023. Yet the implementation of the generation plants, both conventional and non-conventional, and other supporting grid interventions such as Battery Energy Storage Systems (BESS) is lagging behind the timeline envisaged in the plan.

Due to the drastic economic contraction Sri Lanka faced during 2022 most of the projects in transmission and generation were lagged, halted, or not initiated. Securing funds and attracting appropriate investments in the power sector has become increasingly challenging in the present economic situation. Additionally, although the policy targets are set to absorb high renewable share, lack of proper implementation strategies, relevant regulatory outlines and adequate transmission infrastructure hindered addition of expected renewable capacities to the system.

Non implementation of expansion plans creates the risk of having undesirable levels of unserved energy with capacity shortfall. Further it also results in higher energy prices as the reliance on imported high-cost fossil fuels increases. Delays in flexible power plants and energy storage systems with the expected high renewable penetration to the system also poses system stability issues. Hence the timely implementation of the LTGEP is very crucial for the well-being of the system.

1.7 Structure of the Report

The Long Term Generation Expansion Plan 2025-2044 contains following chapters.

Chapter 2	The Existing and Committed Generating Plants
Chapter 3	Electricity Demand: Past and the Future
Chapter 4	Thermal Power Generation Options
Chapter 5	Renewable Generation and Storage Options
Chapter 6	Interconnection Options
Chapter 7	Generation Expansion Planning Methodology and Parameters
Chapter 8	Scenario Analysis
Chapter 9	Reference Case Scenario
Chapter 10	Base Case Scenario
Chapter 11	Environmental implications
Chapter 12	Implementation and Investment of the Base Case Scenario
Chapter 13	Contingency Analysis
Chapter 14	Recommendations of the Base Case Scenario
Chapter 15	Revisions to Previous Plan

CHAPTER 2
EXISTING AND COMMITTED GENERATING PLANTS

2.1 Background

Sri Lankan generation system traditionally consisted of Hydro and Thermal power plants until the early-2010s in which the hydroelectricity was the principal source of electricity generation. Thermal power plants have been operating on imported fossil fuels including diesel, fuel oil and coal. Later the generation mix gradually diversified with the introduction of renewable energy sources such as wind, solar and biomass and further boosted with the launch of rooftop solar power plant scheme in mid-2010s. In 2023, the generation mix consists of 38% of hydro (major & mini hydro), 49% of thermal and 13% of other renewable energy.

Until 1996 the total electricity generation system was owned and operated by CEB and subsequently private sector was also allowed to enter in to electricity generation. Presently the power generation system has CEB owned major hydro, thermal and wind power plants along with thermal, mini hydro, solar, wind and biomass power plants owned by private developers. By the end of 2023, 62% of the total installed capacity is owned by CEB while private sector ownership share is 38% as shown in Table 2.1.

Table 2.1 - Composition of Total Installed Capacity of the System (As of 31st Dec 2023)

Ownership	Plant Type	Capacity (MW)
CEB	Hydro	1,413
	Thermal	1,701
	Wind	103.5
Independent Power Producers (IPP)	Thermal	387
	Mini Hydro	453
	Wind	163
	Solar[1]	953
	Other	54
Total Installed Capacity		**5,194**

[1] Including solar rooftop power plants owned by CEB customers and LECO customers

By the end of 2023 the generation system had an installed capacity of 5,194 MW consisting of 3,501 MW of dispatchable capacity and 1,693 MW of non-dispatchable capacity. Source-wise capacity distribution is depicted in Figure 2.1. In 2023, net generation was 15,728 GWh of which 51% came from renewable energy sources while the remaining 49 % was generated from thermal power plants mainly from coal. Source wise generation is presented in Figure 2.2.

Further, some additional power plants are considered as committed plants in the planning studies. These power plant projects are the projects which are reasonably certain to be added to the system in near future and are in different project development phases including preliminary, procurement, and construction phases. The locations of the existing and committed power plants considered in the study are shown in Annex 2.1 and details are discussed in following sections.

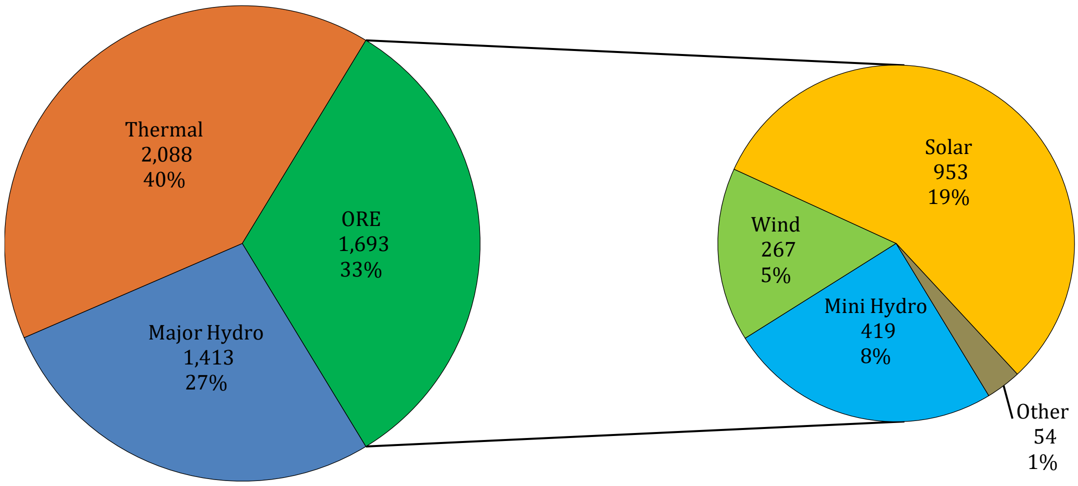


Figure 2.1 - Source-wise Capacity Mix (MW) - 2023[1]

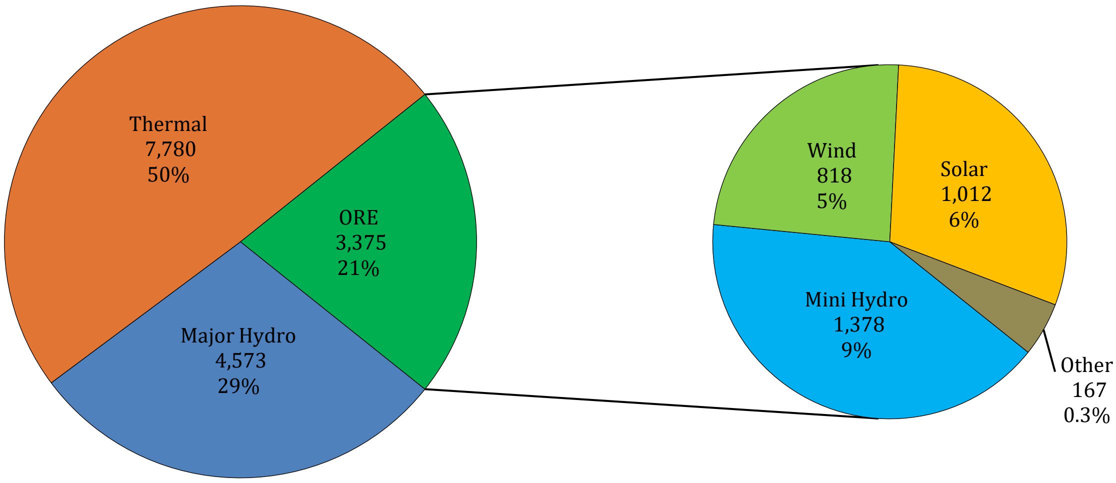


Figure 2.2 - Source-wise Energy Mix (GWh) – 2023[2]

[1]All capacity figures include the capacity of solar rooftop power plants owned by CEB customers and LECO customers.
[2]All energy figures include solar roof top export by rooftop solar power plants owned by CEB customers and LECO customers (estimated) and excludes self-consumption of such plants.

2.2 Hydro and Other Renewable Generation

Hydropower is a vital component of Sri Lanka's energy mix, contributing to both base and peaking electricity generation requirements. It is the main firm renewable source of generation in the Sri Lankan power system and all the major hydro power plants are owned by CEB. Mini hydro power plants which have capacities below 10 MW are owned by the private sector. These are typically non-dispatchable run-of-river type plants.

Other renewable energy (ORE) sources such as wind, solar, biomass and dendro are also an integral part of the Sri Lankan generation system and such power plants are mainly owned by the private developers. Penetration of ORE is expected to further escalate in the planning horizon with the highly ambitious clean energy targets.

2.2.1 Hydro and Other Renewable Power Plants Owned by CEB

By the end of 2023 CEB owned 1,413 MW of hydro power plants which amounts to 77% of the total hydro capacity of the Sri Lankan system. This increased up to 1,535 MW with the addition of Uma oya hydro power plant in April 2024. During 2023 CEB owned hydro power plants generated 4,573 GWh which accounted for 29% of the total net generation. The only ORE plant owned by CEB is the 103.5 MW Thambapavani wind power plant at Mannar.

2.2.1.1 Existing Hydro & Other Renewable Plants

The two prime existing hydropower schemes, namely Laxapana complex and Mahaweli complex, are associated with Kelani and Mahaweli river basins respectively.

Laxapana hydro power complex is strategically located along the two main tributaries of the Kelani River, viz Kehelgamu Oya and Maskeli Oya. Six hydro power stations with a total installed capacity of 388.8 MW belong to Laxapana complex. The operation of these six stations is primarily dedicated to fulfilling the country's power requirements, rather than serving irrigation or other water needs. The key reservoirs within the Laxapana hydropower complex are Castlereigh and Maussakelle, situated at the primary tributaries Kehelgamu Oya and Maskeli Oya, respectively. Castlereigh reservoir, with an active storage capacity of 48 Million Cubic Meters (MCM), supplies water to the Wimalasurendra Power Station, which has a capacity of 50 MW. Meanwhile, Canyon, with a capacity of 60 MW, is driven by the Maussakelle reservoir, which has a storage capacity of 108 MCM. The downstream power stations within this cascaded complex include Old Laxapana (53.8 MW), New Laxapana (100 MW), Polpitiya (Samanala) (90 MW) and recently commissioned Boradlands (35 MW).

It is noteworthy that additional water releases from Laxapana complex can be expected in the dry season as Colombo water supply is catered through Kelani river, hence the power generation can be affected during such seasons.

The development initiatives taken under the Accelerated Mahaweli Development Program have significantly augmented Sri Lanka's hydroelectric capacity by integrating Mahaweli hydro power complex to the national grid with seven power stations with a collective installed capacity of 816.8 MW. Three major reservoirs, Kotmale, Victoria, and Randenigala, which are fed by Mahaweli river, were constructed as part of the development program and they directly facilitate cascaded Kotmale (201 MW), Victoria (210 MW) and Rendenigala (122.6 MW) power stations. Upper Kotmale (150

MW) run-of-river power station, which is situated upstream of Kotmale reservoir, is fed by a tributary of Mahaweli river, Kotmale oya while Rantambe (50 MW), which is situated downstream of Randenigala reservoir, is driven by the waters of both Uma oya and Mahaweli ganga. After power generation of this cascading power plant system, water is released to downstream Mahaweli B, C, E irrigation zones via Minipe weir.

Furthermore, the Polgolla diversion weir, across the Mahaweli Ganga, downstream of Kotmale and upstream of Victoria, plays a pivotal role in diverting Mahaweli waters for irrigation purposes via the Ukuwela (40 MW) power station. After generating electricity at Ukuwela, the discharged water flows into the Sudu Ganga, upstream of Amban Ganga. This water is then directed to the Bowatenna reservoir, which in turn supplies both the Bowatenna power station (40 MW) and Mahaweli System-H (primarily) through distinct waterways. Water discharged through the Bowatenna power station subsequently enters the Elahera Ela, making it available for diversion to Mahaweli systems D and G, ensuring efficient water management and utilization across multiple sectors.

It should be specifically noted that the Mahaweli hydro system is developed as a multi-purpose system and the water release precedence is as follows,

i. Drinking water supply
ii. Environmental considerations
iii. Irrigation requirements
iv. Electricity generation

Hence power generation from the associated power stations is dependent on the down-stream irrigation requirements also. These irrigational requirements, being highly seasonal, affects the operation of these power stations during certain periods of the year. It is notable that even in dry seasons where hydrological situation is poor, these power stations are compelled to run to release water for irrigational requirements.

The third major hydro power complex in Sri Lanka is the Samanala Complex with cumulative 207.8 MW capacity. This complex consists of two large hydro power plants Samanalawewa (120 MW) and Kukule (75 MW). Samanalawewa is supplied from the Samanalawewa reservoir with active storage of 168 MCM and it is fed from Walawe river. In this reservoir there can also be relatively small irrigation water releases occasionally. Kukule is a run-of-river type hydro power plant and is supplied by Kukule ganga which is a tributary of Kalu ganga river.

The latest addition to the Sri Lankan hydropower system is the122 MW Uma oya hydro power plant developed under Uma Oya Multipurpose Development Project, which was connected to the national grid on April, 2024. In addition to power generation, water from the Uma oya reservoir is used for drinking water and irrigational purposes. Therefore, the power generation will depend on such releases also. (This is not considered in capacity & energy figures presented as of Dec 2023).

Additionally, there are three relatively small hydro power plants Inginiyagala (8.7 MW) -Samanala complex, Udawalawe (4 MW) – Samanala complex and Nilambe (3.2 MW) – Mahaweli complex, contributing to nations hydro power generation, but their generation is dependent on irrigation water releases from the respective reservoirs.

103.5 MW Mannar wind park is the first large scale CEB owned ORE plant added to the national system. It is situated at the southern coast belt of the Mannar islands. It consists of 30 windmills of each having 3.45 MW capacity and is a semi dispatchable plant. An extension of 50 MW is expected to be added to the plant in the near future.

Details of the existing CEB owned hydro and ORE power plants considered in planning studies are given in Table 2.2 and the schematic diagrams of the hydro reservoir networks are shown in Annex 2.2.

2.2.1.2 Committed Hydro & Other Renewable Plants

The only committed CEB owned hydro power plant in the pipeline is the Moragolla Hydro Power project with a reservoir of 1.98 MCM active storage. It is currently under construction and expected to be added to the system during 2024. It is located on the Mahaweli river close to Ulapane village in Kandy District of Central Province. The rated head of the plant is 69m. This committed power plant has a capacity of 30.2 MW (2 x 15.1 MW) and 97.6 GWh of mean annual energy prospect.

There are no ORE projects which can be considered as committed plants under the purview of CEB, particularly due to the current stringent financial condition of the entity and the country.

2.2.2 Other Renewable Power Plants Owned by Independent Power Producers

2.2.2.1 Existing Other Renewable Plants

Since the policy decision to permit private sector investors to develop hydro power plants below 10 MW capacity in 1996, over 200 mini hydro plants amounting to total capacity over 400 MW have been connected to the national grid. Additionally, small scale private sector power plants based on wind, solar and other technologies such as biomass, dendro, solid waste have been added to the national grid during the past three decades. With the ambitious renewable energy targets there has been a promising growth in ORE additions during the past few years.

Total capacity of these ORE plants is approximately 1,590 MW as of 31st December 2023 and the source-wise capacity contribution of ORE plants is tabulated in Table 2.3. These plants are mainly connected to 33 kV medium voltage distribution lines.

Further, there has been a substantial increase in rooftop solar capacity additions in recent years owing to the favorable conditions provided to the electricity users such as higher tariffs and concessional loan facilities. Rooftop solar power plant capacity, integrated to both MV & LV networks, by the end of 2023 is illustrated in Table 2.4.

Table 2.2 - Existing CEB Owned Hydro & ORE Power Plants (As of 30th April 2024)

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg. Energy (GWh)	Active Storage (MCM)	Rated Head (m)	Year of Commissioning
Canyon	2 x 30	60	160	107.9 (Maussakelle)	203	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	47.93 (Castlereigh)	226.1	1965
Old Laxapana	3 x 9 2 x12	50	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 50	100	552	0.629 (Canyon)	541	1974 - Unit 1 1974 - Unit 2
Polpitiya	2 x 45	90	453	0.113 (Laxapana)	259	1969
Broadlands	2 x 17.5	35	126	0.198 (Polpitiya)	56.9	2022
Laxapana Total		**385**	**1,689**			
Upper Kotmale	2 x 75	150	409	0.8	473.0	2012 - Unit 1 2012 - Unit 2
Victoria	3 x 70	210	865	688	190.0	1985 - Unit 1 1984 - Unit 2 1986 - Unit 3
Kotmale	3 x 67	201	498	154	201.5	1985 - Unit 1 1988- Unit 2 & 3
Randenigala	2 x 60	120	454	536	77.8	1986
Ukuwela	2 x 19.3	40	154	2.5	75.1	1976 - Unit 1&2
Bowatenna	1 x 40	40	48	21.5	50.9	1981
Rantambe	2 x 25	50	239	2.8	32.7	1990
Nilambe	2 x 1.61	3	-	0.05	110.0	1988
Mahaweli Total		**814**	**2,667**			
Samanalawewa	2 x 60	120	344	168.3	320.0	1992
Uma Oya	61 x 2	122	290	0.7	722	2024
Kukule	2 x 37.5	75	300	1.79	186.4	2003
Udawalawa	3 x 2	6		187.6	14.3	1969
Inginiyagala	2 x 2.475, 2 x 3.15	11.25		844.9	27.1	1951
Samanala Total		**334.25**	**966**			
Existing Major Hydro total		**1,533.25**	**5,322**			
Mannar Wind Park		103.50	337			2020
Existing Other Renewable		**103.50**	**337**			
Existing Total		**1,636.75**	**5,659**			

Table 2.3 - Existing IPP Owned ORE Power Plants (As of 31st Dec 2023)

Project Type	Number of Projects	Capacity (MW)
Mini Hydro Power	212	419
Wind Power	19	163
Solar Power (Scatterred, Ground Mounted)	86	138
Other (Dendro, Biomass, Municipal Solid Waste)	14	54
Total ORE (Excluding Rooftop Solar)	**331**	**775**

Table 2.4 - Existing Rooftop Solar Power Plants (As of 31st Dec 2023)

Project Type	Number of Projects	Capacity (MW)
Facilitated by CEB	39,827	657
Facilitated by LECO	15,173	158
Total Rooftop Solar	**55,000**	**815**

2.2.2.2 Committed Other Renewable Plants

In order to attain the high renewable energy absorption targets, CEB has taken steps to attract more private sector investments in developing renewable energy plants. There are several small scale, up to 10 MW, projects being implemented under the Standard Power Purchase Agreements (SPPA) in accordance with feed-in-tariff scheme and through tendering. There are several on-going projects which are in different maturity stages and new projects are being initiated constantly.

Large scale projects are mainly realized under competitive tendering process. The Siyambalanduwa Solar Power Project is a major renewable energy initiative in Sri Lanka, aimed at boosting the country's clean energy capacity. Located in the Monaragala District of Uva Province, this 100 MW ground-mounted solar park is a key step in Sri Lanka's transition towards sustainable energy. With an investment of approximately USD 152 million, the project is expected to be completed by 2026. In addition to generating clean electricity, the project will also include the construction of a 132 kV transmission facility to connect the solar park to the national grid.

The 50 MW wind park at Mannar shall be developed through private sector investments, through a competitive tendering scheme. The project is at its final stages of approval for awarding, and is expected to be commissioned in 2026, as main transmission infrastructure is already available and key approvals are already obtained.

In addition, rooftop solar projects are also being continuously added to the system on a daily basis. It is expected that approximately 150 MW of rooftop solar projects shall be connected to the distribution network providing embedded generation to the Sri Lankan grid.

2.2.3 Summary of Renewable Power Generation

A summary of the existing total renewable capacities is summarized in Table 2.5.

Table 2.5 -Existing Renewable Power Plants (As of 31st Dec 2023)

Renewable Source	**Capacity (MW)**
CEB Owned	
Major Hydro	1,413
Wind	104
Private Owned	
Mini Hydro	419
Solar	
Scattered, Ground Mounted	138
Rooftop Solar Facilitated by CEB	657
Rooftop Solar Facilitated by LECO	158
Wind	163
Other	
Dendro	27
Biomass	17
Waste to energy	10
Renewables Total	**3,107**

2.3 Thermal Generation

2.3.1 Thermal Power Plants Owned by CEB

2.3.1.1 Existing Thermal Plants

Majority of the thermal power plants, over 81% of total thermal capacity connected to the national grid, is owned by CEB. Total CEB owned thermal capacity is 1,701 MW from which 900 MW is from Lakvijaya Coal power plant. The remaining 801 MW is fueled mainly by Naptha, Fuel Oil and Diesel. Details of the CEB owned thermal plants are presented in Table 2.6.

The Kelanitissa Power Station in Colombo comprises multiple units, including a combined cycle plants and a gas turbine power station, they operate primarily from diesel, while the KCCP 1 can also operate on Naptha. The Sapugaskanda Power Plant, also near Colombo, runs on heavy fuel oil and plays a crucial role in the power grid. Another important facility is the Colombo barge-mounted power plant that also runs on fuel oil, adding much required capacity to the thermal generation fleet. In the Northern Province, the Uthuru Janani Power Plant supports regional energy needs, utilizing heavy fuel oil as well.

The Lakvijaya Power Plant, is the largest power station in Sri Lanka and plays a significant role in the country's energy sector. It uses imported coal, primarily from Indonesia, and contributes around 40% of Sri Lanka's total electricity generation. Lakvijaya Power Plant remains a cornerstone of the CEB's generation portfolio due to its ability to provide stable, base-load power, especially during periods of low hydroelectric production.

Technical parameters and cost details of the existing thermal generation plants taken as input to the planning studies are summarized in Table 2.7.

It should be noted that Small GTs in Kelanithissa (KPS Frame 5 GTs) are considered to be retired before the beginning of the planning horizon, however two units of the power plant is expected to be retained in the system for Colombo power restoration after total or partial blackout situation, until a suitable power plant or battery energy storage system which provide such service is added to the system.

Table 2.6 - Details of Existing CEB Owned Thermal Power Plants (As of 31st Dec 2023)

Plant Name	No of Units x Name Plate Capacity (MW)	No of Units x Capacity used for Studies (MW)	Annual Max. Energy (GWh)	Commissioning
Puttalam Coal Power Plant				
Lakvijaya CPP	3x300	3x270	5,355	2011 & 2014
Puttalam Coal Total	**900**	**810**	**5,355**	
Kelanitissa Power Station				
Gas turbine (Small GTs)	4 x 20	4 x 17	382	Dec 1981 Mar 1982 Apr 1982
Gas turbine (GT 7)	1x 115	1 x 115	703	Aug 1997
Combined Cycle-1	1x 165	1 x 161	1,196	Aug 2002
Combined Cycle-2	1x163	1x155	1,182	Acquired in 2022
Kelanitissa Total	**523**	**499**	**3,463**	
Sapugaskanda Power Station				
Station A	4 x 20	4 x 17	493	May 1984 May 1984 Sep 1984 Oct 1984
Station B	8 x 10	8 x 9	481	Sept 1997 -4 Units Oct 1999 - 4 Units
Sapugaskanda Total	**160**	**140**	**974**	
Other Thermal Power Plants				
Uthuru Janani	3 x 8.9	3 x 8.9	184	Jan 2013
Barge Mounted Plant	4 x 15.6	4 x 15.6	515	Acquired in 2015
Containerized Emergency Plant	50 x 1	50 x 1		2019
Existing Total Thermal	**1,722.10**	**1,588.10**	**10,491**	

Table 2.7 - Characteristics of Existing CEB Owned Thermal Power Plants Considered in Planning

Name of Plant	Units	Kelanitissa			Sapugaskanda		Lakvijaya	Other		
		GT 7	Comb. Cycle 1	Comb. Cycle 2	Station A	Station B	Coal	Uthuru Janani	Barge Mounted Plant	Emergency Plant 50x1
Basic Data										
Engine Type		FIAT (TG 50 D5)	VEGA 109E ALSTHOM	GE FRAME 9E	PIELSTIC PC-42	MAN B&W L58/64	-	Wartsila 20V32	Mitsui MAN B&W 12K50MC-S	Perkins 4012 dG
Input Parameters for Studies										
Number of Units		1	1	1	4	8	3	3	4	50
Unit Capacity	MW	115	161	155	17	9	270	8.9	15.6	1
Minimum operating level	MW	80	130	70	11	7	150	2.67	8.5	0.5
Fuel Type and Calorific Value	kCal/kg	Diesel 10,500	Naptha-10,880 Diesel-10,500	Diesel 10,500	Fuel Oil - 10,300	Fuel Oil - 10,300	Coal-6300	Fuel Oil - 10,300	Fuel Oil - 10,300	Diesel 10,500
Heat Rate at Min. Load[1]	kCal/kWh	3,188	Naptha - 1,911.1 Diesel-2,072.9	2,457	2,276	2,136	Unit 1-2977 Unit 2-2,654 Unit 3-2,655	2,132	2,111	2,527
Heat Rate at Full Load[1]	kCal/kWh	2,923	Naptha - 1,818.8 Diesel-1,953.4	1,996	2,248	2,081	Unit 1-2,478 Unit 2-2,445 Unit 3-2,318	2,132	2,111	2,353
Fuel Cost[2]	USCts/GCal	8,005	Naptha - 7,650 Diesel-8,005	8,005	7,581	7,581	2,111	7,581	7,581	8,005
Forced Outage Rate	%	6.8	8	8	6.8	5.8	8	7.5	5.2	67
Full Load Efficiency	%	29	Naptha - 46.32 Diesel-42.46	42.8	38	41	Unit 1-34.8 Unit 2-35.2 Unit 3-37.2	44	40	36
Fixed O&M Cost	$/kWmonth	0.20	2.10	1.26	2.94	2.94	2.34	1.97	1.03	
Variable O&M Cost	$/MWh	0.75	2.22	1.01	3.46	5.13	2.69	5.13	5.13	8.8

[1] Heat rates and calorific values are given in HHV

[2] All costs are in border prices. Fuel prices are based on Chapter 4 -Section 4.3.

2.3.1.2 Plant Retirements and Extensions

For planning studies retirement dates of CEB owned existing thermal power plants are considered as indicated in Table 2.8. However, decision on the retirement of power plants will be considered by evaluating the actual plant condition and the implementation progress of planned power plant additions.

Further, after careful evaluation of refurbishment costs against potential benefit of extending operating lifetime of the power plants, it was decided to extend the retirement year of Sapugaskanda A, Sapugaskanda B & Barge power plants by another 5 years.

Table 2.8 - Power Plant Retirement Schedule

Power Plant	Year of Retirement[1]	Year of Retirement after Refurbishment
KPS Small GTs	2025	
KPS GT7	2026	
Sapugaskanda PS A (4 units)	2026	2031
Sapugaskanda PS B (8 Units)	2026	2031
Barge Mounted Power Plant	2026	2031
Kelanithissa Combined Cycle Plant-1	2033	
Kelanithissa Combined Cycle Plant-2	2033	
Uthurujanani	2033	
Lakvijaya – Unit 1	2041	
Lakvijaya – Unit 2	2044	
Lakvijaya – Unit 3	2044	

[1]Power plant retirements are assumed to be at the beginning of each year

2.3.1.3 Committed Thermal Power Plants

CEB has planned to develop a 130 MW Gas turbine power plant at Kelanitissa premises. This power plant is supposed to be added to the system in 2030. However, taking the current financial position of the entity and the country into account, it can also be developed as a IPP power plant.

2.3.2 Thermal Power Plants Owned by Independent Power Producers

2.3.2.1 Existing Thermal Plants

Combined cycle power plant at Kerawalapitiya, owned by West Coast (Pvt)Ltd was added to the national grid in May 2010 for a 25 year contract period with a capacity of 270 MW.

2.3.2.2 Committed Thermal Plants

Table 2.9 outlines the committed IPP thermal projects.

Table 2.9 - Details of Committed IPP Owned Thermal Power Plants

Plant Name	Capacity used for Studies (MW)	Commissioning	Contract Period (Yrs.)
Sobadhanavi Ltd. Combined Cycle Power Plant	350	GT- 2024 ST–2025	20
2nd Combined Cycle Power Plant at Kerawalapitiya	350	GT- 2026 ST–2027	25
IC Engine Power Plant at Kerawalapitiya	200	2028	20
Committed Total IPP	**900**		

CHAPTER 3
ELECTRICITY DEMAND

3.1 Past Demand

Demand for electricity in the country during the decade up to 2021 has been growing at an average rate of approximately 4% per annum while peak demand has been growing at a rate of 3% per annum. COVID 19 pandemic's disruptive impacts on global supply chains, trade, and consumer behavior prompted widespread economic contractions after 2020. It is observed the demand in 2020 has contracted by 1.8% compared to 2019. However, in 2021 electricity consumption increased by 6.2% and returned to pre-pandemic level. Recovery in electricity demand in 2021 is mainly due to the surge in economic activities amid easing of lockdown restrictions.

However, in the wake of the prolonged economic crisis, businesses experienced closures, causing widespread unemployment and income reductions. Against this challenging backdrop, electricity demand saw a decline once again, reflecting the stalling of industries and financial constraints faced by individuals. The economic downturn forced businesses to scale back operations, leading to a reduction in industrial power requirements. Simultaneously, rising unemployment and financial constraints prompted households to adopt energy conservation measures, affecting residential consumption. Additionally, the diminished commercial activity resulted in a noticeable drop in workplace and retail electricity usage. The subsequent imposition of increased electricity tariffs only served to deepen the economic hardships faced by society.

Amidst these compounding challenges, the repercussions on energy demand have been substantial. Over the period of three years from 2021 to 2023, peak demand has contracted by 7.2% marking the highest reduction over the past decade. Overall energy demand has seen a significant reduction of 3.2% (Table 3-1). This symbolizes the interdependence between the country's economy and growth in electricity.

In 2023, net electricity generated to meet the demand amounted to 15,728 GWh (including rooftop solar energy exported to grid but excluding self-consumption), which had been 16,060 GWh in 2022 which shows a 2.1% reduction. The recorded maximum demand within the year 2023 was 2,415 MW, which was 2,708 MW in year 2022 indicating a 10.8% reduction.

Regarding the system losses, a gradual reduction could be observed over time as shown in Table 3-1. The actual losses vary depending on the generation combination of each year, specifically with the contribution from distributed renewable generation such as solar rooftop plants. Total system loss incurred in the year 2023 is 9.7% of net generation. The average net loss of past five years is 9.4% which is on par with other developing countries.

Figure 3.1 shows the percentage consumption shares among different consumer categories from 1984 to 2023. In 2023, the share of domestic consumption in the total demand was 36% while that of industrial and commercial sectors were 32% and 30% respectively. Religious purpose consumers and street lighting, which is referred to as the other category, together accounted only for 1%. Similarly in 2014 (10 years ago), share of domestic, industrial, commercial and religious purpose & street lighting consumptions in the total demand, were 37%, 34%, 27% and 2% respectively.

Table 3.1 - Electricity Demand in Sri Lanka 2009-2023

Year	Energy Sales[1] (GWh)	Avg. Growth (%)	T & D Losses (%)	Net Generation[2] (GWh)	Avg. Growth (%)	Recorded Peak (MW)	Avg. Growth (%)
2009	8,358	0.1	14.7	9,803	-0.2	1,868	-2.8
2010	9,191	10.0	13.7	10,649	8.6	1,955	4.7
2011	9,973	8.5	12.2	11,353	6.6	2,163	10.6
2012	10,389	4.2	11.4	11,725	3.3	2,146	-0.8
2013	10,538	1.4	11.4	11,898	1.5	2,164	0.8
2014	10,983	4.2	10.8	12,316	3.5	2,152	-0.6
2015	11,704	6.6	10.6	13,090	6.3	2,283	6.1
2016	12,696	8.5	10.3	14,148	8.1	2,453	7.4
2017	13,358	5.2	9.0	14,671	3.7	2,523	2.9
2018	14,023	5.0	8.8	15,374	4.8	2,616	3.7
2019	14,556	3.8	8.9	15,982	4.0	2,669	2.0
2020	14,288	-1.8	9.5	15,780	-1.3	2,717	1.8
2021	15,180	6.2	9.6	16,798	6.5	2,802	3.1
2022	14,536	-4.2	9.5	16,060	-4.4	2,708	-3.4
2023	14,195	-2.3	9.7	15,728	-2.1	2,415	-10.8
Last 3 year		-3.2%			-3.2%		-7.2%
Last 5 year		-0.6%			-0.4%		-2.5%
Last 10 year		2.9%			2.8%		1.3%
Last 15 year		3.9%			3.4%		1.9%

[1] Aggregate sales to consumers by CEB and LECO

[2] Net generation including CEB and LECO rooftop solar energy exported to grid from 2019 onwards

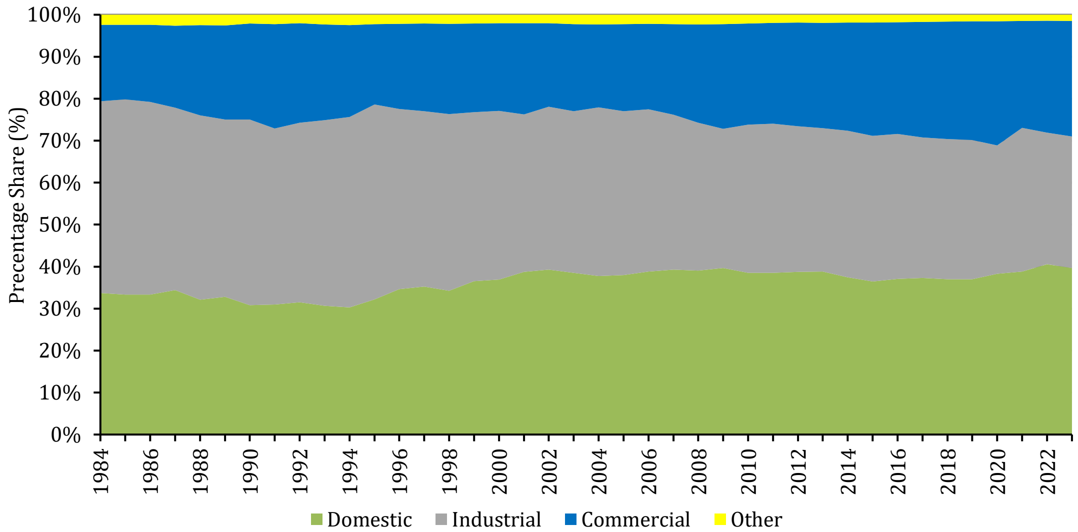


Figure 3.1 - Consumption Share among Consumer Categories

3.2 Daily Demand Curve and Load Factor

Significant increase in the number of renewable power plants in the Sri Lankan system in the recent past poses challenges in accurately estimating the daily demand curve. Nevertheless, over the past few years, initiatives have been implemented to acquire real-time data from most renewable power plants. However, a few projects still encounter technical limitations hindering real-time data acquisition, which are anticipated to be resolved in time. At present, there are no measures in place to monitor solar rooftop self-consumption. Hence an estimation is required to accurately assess the true shape of the daily load curve.

Accordingly, the recorded demand with telemetered renewables and the estimated demand including non-metered renewables and solar rooftop self-consumption on a typical weekday in 2023 is shown in Figure 3.2.

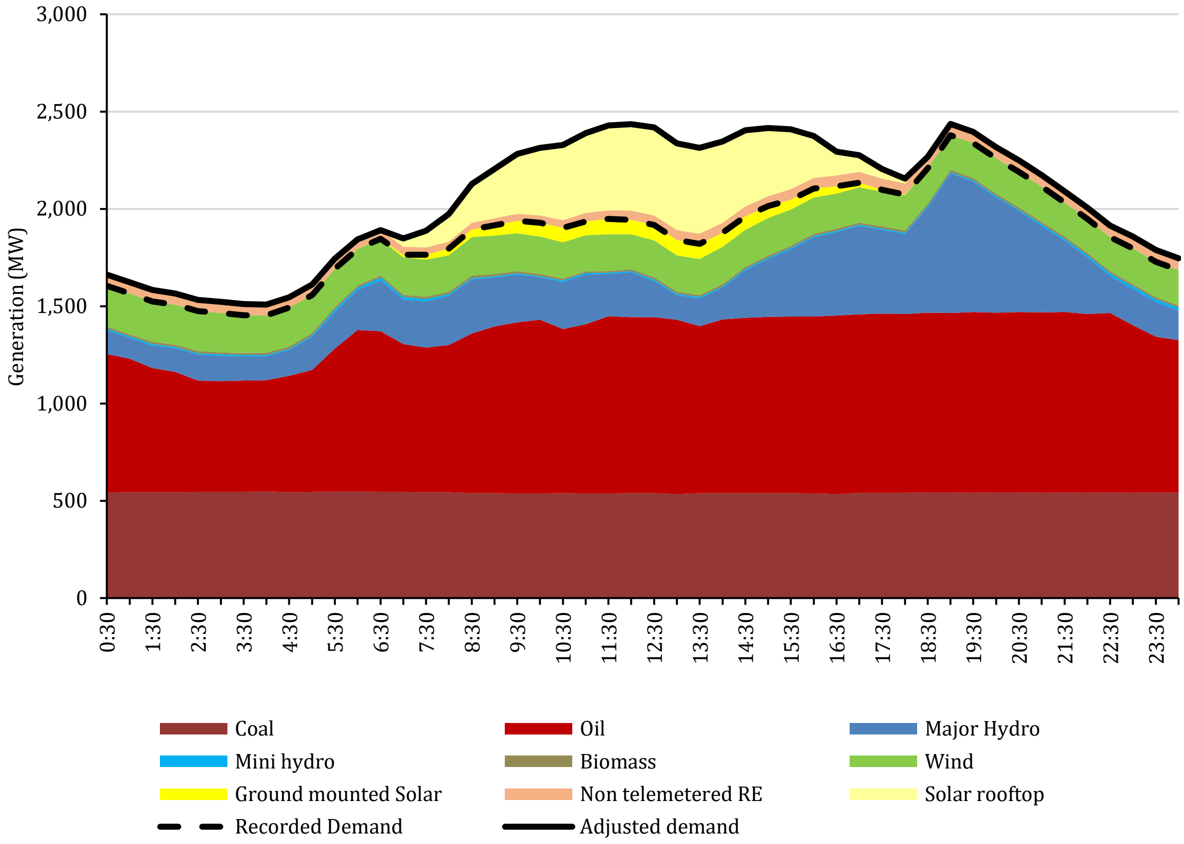


Figure 3.2 - Daily Load Curve of a Typical Day in 2023

This adjustment was carried out for the demand data for the year 2023 and it was observed that day peak exceeded night peak approximately 50% of the days of the year. Hence, from the above analysis it was concluded that the occurrence of days with day peak exceeding night peak are common in the present system.

Load factor (LF) which is an indication of the pattern of the daily demand curve provides insights into the utilization and efficiency of the system. Figure 3.3 shows the recorded and the adjusted system load factor variation over the last 15 years which is based on net generation.

Even though there are fluctuations in LF historically, it has improved over time and reached 75% in 2023. In addition to the gradual increase of the day peak over time, the significant reduction in night peak in the recent past as explained in section 3.1 has contributed to this improvement of the load factor.

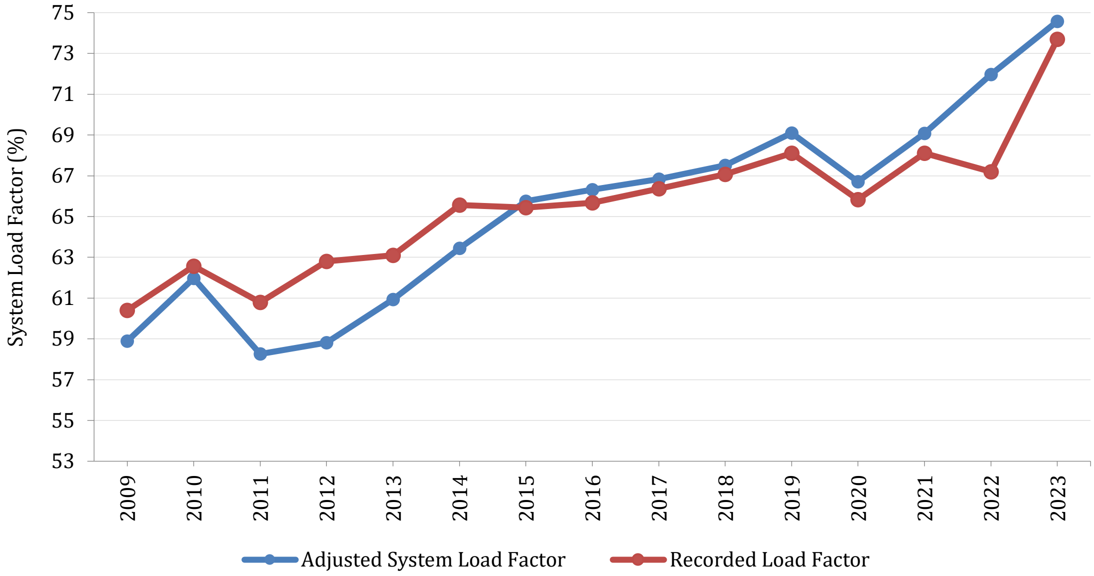


Figure 3.3 - Past System Load Factor

3.3 Policies and Guidelines

The Electricity Demand Forecast 2025-2049 is prepared complying with the following policies and guidelines.

a) National Energy Policy and Strategies of Sri Lanka, August 2019
b) General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka, 2021 issued in January 2022
c) Generation Planning Code in the Draft Grid Code issued by the Transmission Licensee, Ceylon Electricity Board, in September 2023

3.4 Demand Forecasting Methodology

A combination of medium term and long term forecast approaches has been adopted for the preparation of base demand forecast 2025-2049. To determine the medium term (initial five years) electricity demand forecast, outcome of Time Series modelling, Time Trend modelling and forecasts from distribution licenses were taken into the analysis. For the long term, an econometric approach has been adopted by analysing past electricity energy demand figures with several independent variables. In addition, major development projects were also considered. For analysis purpose, past annual electricity demand was considered by adjusting annual electricity sales with energy not served from scheduled power outages, estimated rooftop solar self-consumption and any other self-generation to represent the overall national electricity demand.

In addition to the base demand forecast, a number of demand forecast scenarios and sensitivities were prepared for the planning horizon. Considering the most recent policy directives steering towards the transition to e-mobility, a separate analysis was conducted which is described in section 3.6. In addition, other demand forecasting scenarios and sensitivities are described in section 3.7.

3.4.1 Medium Term Demand Forecast (2025-2029)

After comprehensive analysis on the behavior of the demand pattern in the recent past it was determined that time series modelling would best represent the seasonal variations throughout the year into the medium-term modelling process.

In order to capture the impact of weather and structural shock effects (such as COVID-19 and sudden economic downturn), time series model was detrended according to following equation. This method decomposes the demand into any trend, seasonality, and residual. Incorporating the date variable (time in months) into the model enables the regression to allocate a coefficient to a trend that has occurred within the period of concern. A seasonal (monthly) model is then fitted to the detrended data based on the weather variable Cooling Impact (CI). This is used to quantify deviations in weather patterns from normal conditions. [7]

$$TotDem(t) = 5.09\ t + 39.83\ CI(t) - 102.84\ SI(t) + 829.49$$

Where,

TotDem(t)	-	Monthly electricity demand including rooftop solar (GWh)
t	-	Time in months
CI(t)	-	Cooling Impact It is defined as the number of degrees (∘ C) that a month’s average temperature is above a critical temperature threshold. Shock Impact (0,1)
SI(t)	-	Dummy variable that captures the changes in demand due to external shock

Above model will capture the trend over time, weather dependent seasonality and the impact of recent COVID-19 and financial downturn into the medium-term model.

Furthermore, an analysis was conducted to identify the impact on electricity demand due to recent tariff variations. Until recently Sri Lankan electricity tariffs were not cost reflective and were not revised in regular periods, contrary to the common practice around the world. Further electricity tariffs were comparably low and most of the customers in the largest consumer group, the domestic category was heavily subsidized. Hence historically electricity demand in Sri Lanka has been price inelastic. With the recent adaptation of cost reflective tariffs which are to be revised biannually, there have been changes in consumption in response to the tariff change.

Some changes in the electricity usage in response to the tariff can be observed as mentioned below.

i. Overall sales have decreased in some categories like domestic and industrial but slowly reaching the pre-tariff revision levels again.
ii. Domestic customers who were in higher consumption blocks have moved to lower consumption blocks.

It is essential to understand that it is difficult to capture the sales variation purely attributed to tariff change as fluctuations also result from weather changes and severe economic fallout specifically in industries and businesses during the recent past. Also, there was a significant load shedding during 2022 and beginning of 2023 altering consumption. Moreover, it is only approximately one year since the periodic tariff revision implemented, hence only limited data was available to carry out the study. However, from price elasticity in the short-term analysis from August 2022 to October 2023, it can be observed that price elasticity is not substantial during this period.

3.4.2 Long Term Demand Forecast (2030-2049)

Econometric modelling was used for the long term demand forecasting from 2030 to 2049, giving due consideration to the electricity consumer tariff categories (multisector) and economic growth of sectors [8]. To capture different consuming habits of various consumer categories, sector-wise forecasts were prepared separately. Therefore, 'Domestic', 'Industrial', 'Commercial' (including General Purpose, Hotels and Government) and 'Other' (Religious purpose and Street Lighting) sectors were analysed separately to capture the different consuming habits within categories.

In the models, annual electricity demand (sales figures adjusted with energy not served, estimated rooftop solar self-consumption and any other self-generation) figures of the past were analysed against several independent variables as given in Table 3.2 using multiple regression technique. During the process, some of the insignificant independent variables were eliminated.

Table 3.2 - Variables Used for Econometric Modelling

Sector	Variables
Domestic	Gross Domestic Product, GDP Per Capita, Population, Avg. Electricity Price, Previous Year Demand, Domestic Consumer Accounts, Previous year Domestic Consumer Accounts
Industrial	Gross Domestic Product, Previous Year GDP, Population, Avg. Electricity Price, Previous Year Demand, Agriculture Sector Gross Value Added, Industrial Sector Gross Value Added, Service Sector Gross Value Added, Industrial Consumer Accounts, Previous year Industrial Consumer Accounts
Commercial	Gross Domestic Product, Previous Year GDP, Population, Avg. Electricity Price, Previous Year Demand, Agriculture Sector Gross Value Added, Industrial Sector Gross Value Added, Service Sector Gross Value Added, Commercial Consumer Accounts, Previous year Commercial Consumer Accounts
Other	Past Demand

The resulting final regression coefficients together with assumptions about the expected growth of the independent variables are then used to project the electricity demand for three different sectors. The following are the derived multiple linear regression models used in econometric analysis.

3.4.2.1 Domestic Sector

In regression analysis, it was found that the two significant variables Gross Domestic Product Per Capita and Previous year Electricity Demand in Domestic consumer category were significant independent variables for the domestic sector demand growth. The econometric model is as follows, where t indicates years:

Ddom (t) = 0.95 GDPPC (t) + 0.95 Ddom (t-1) – 49.95

Where,

Ddom (t)	- Electricity demand in domestic consumer category (GWh)
GDPPC (t)	- Gross domestic product per capita ('000s LKR)
Ddom (t-1)	- Previous year electricity demand in domestic consumer category (GWh)

3.4.2.2 Industrial Sector

The significant variables for electricity demand growth in this sector are Industrial sector Gross Value Added (GVA), Industrial consumer accounts and previous year Electricity demand in Industrial consumer category. The econometric model is as follows, where t indicates years:

Dind (t) = 0.26 GVAind (t) + 23.02 CAind (t) + 0.44 Dind (t-1) + 117.63

Where,

Dind (t)	- Electricity demand in industrial consumer categories (GWh)
GVAind (t)	- Industrial sector gross value added ('000 LKR)
CAind (t)	- Industrial consumer accounts ('000s)
Dind(t-1)	- Previous year electricity demand in industrial consumer category (GWh)

3.4.2.3 Commercial Sector

Significant variables for electricity demand growth in the commercial sector are Service Sector Gross Value Added and previous year Electricity demand in Commercial consumer category. Although there are differences between the identification of Commercial (General Purpose, Hotel & Government) sector in CEB Tariff category and Service sector identified in the statistics of Central Bank of Sri Lanka, Service sector GVA was selected as the most significant variable in regression analysis. The econometric model is as follows, where t indicates years:

Dcom (t) = 0.20 GVAser (t) + 0.71 Dcom (t-1) – 196.10

Where,

Dcom (t)	-	Electricity demand in commercial consumer categories (GWh)
GVAser	-	Service sector gross value added ('000 LKR)
Dcom (t-1)	-	Previous year electricity demand in commercial consumer category (GWh)

3.4.2.4 Other Sector

The two consumer categories: Religious purpose and Street Lighting were considered in the 'Other Sector' considering the diverse nature of the consumers included in this category, this category was analysed without any links to other social or demographic variables. Hence, the time-trend analysis using logarithm approach was performed to predict the demand in this sector.

$$\ln(D_{oth}(t)) = 0.048\,t - 91.31$$

Where,

Doth (t)	-	Electricity demand in other sector consumer category (GWh)
t	-	Year

3.4.2.5 Forecast of Independent Variables

Main economic variable which needs to be forecasted is the GDP. Sector-wise (Industry, Services and Agriculture) GDP growth rate projections for 2025 and 2026 were obtained from the report Sri Lanka Development Update, April 2023 published by the World Bank. Accordingly, the GDP structure is assumed to be approximately 27% from Industry sector, 60% from services and 8% from Agriculture sector for the planning horizon. From 2027 onwards, annual average GDP growth rate of 5.6% was considered. Furthermore, the population forecast was derived based on the data from Department of Census and Statistics and consumer account forecast was derived based on the forecast data given by distribution licensees.

3.4.3 Future Major Development Projects

The Government has proposed and planning for large scale developments which brings more demand in electricity sector in the future. The major developments plans are identified by Ministry of Urban Development and Housing, Ministry of Water Supply & Estate Infrastructure Development. Currently, these developments are under different stages including feasibility study, planning and construction.

Above ministries have identified the following major developments under their respective development programs.

- Colombo Port City Development
- Western Region Light Rail Transit Project
- Colombo Railway Electrification Project
- Solid Waste Management Project
- Metro Colombo Urban Development Project

Colombo Port City Development Project cumulative peak electricity demand requirement will gradually increase starting from 20 MW in 2024 and reach 365 MW in 2042. For the Western Region Light Rail Transit Project, cumulative peak electricity demand requirement is given as 195 MW by 2027 and reach 222 MW by 2036. According to the information received, the cumulative peak electricity demand requirements for of other main development projects is indicatively estimated as 235 MW by 2024, 487 MW by 2035 and 632 MW by 2044.

3.4.4 Cumulative Electricity Demand Forecast

Once the electricity demand forecast was derived based on the econometric approach, forecasts of four sectors were added together to derive the demand forecast from 2030 to 2049. Cumulative electricity demand forecast 2025-2049 is the combination of medium term and long term approaches with the consideration of future major development projects as described in 3.4.1 to 3.4.3 above.

3.4.5 Net Generation Forecast

To obtain the net generation forecast it is required to forecast the system losses. Estimated total net energy loss (transmission and distribution loss) were added to the cumulative electricity demand forecast (obtained in section 3.4.4) in order to derive the net electricity generation forecast.

Transmission and distribution loss is expected to reduce gradually from 7.9% in year 2025 to 7.25% towards the end of the planning horizon. However, the actual losses would vary depending on the actual generation combination of each year. In 2023, the actual loss was 9.3% whereas in 2022 it was 8.8%.

3.4.6 System Load Factor and Peak Demand Forecast

As explained in section 3.2 above, it is observed that day peak and night peak falls within the comparable range. Furthermore, this was validated by analysing the extrapolated trend lines of monthly records of day peak, night peak and off peak from 2011 to 2021. As shown in Figure 3.4, the growth of day peak is higher than the growth of night peak. Therefore, in the future more energy will be relatively filled in the daytime of the load profile resulting in the shape of the daily load profile to gradually change and it could be expected that the day peak of the country will become higher than the night peak.

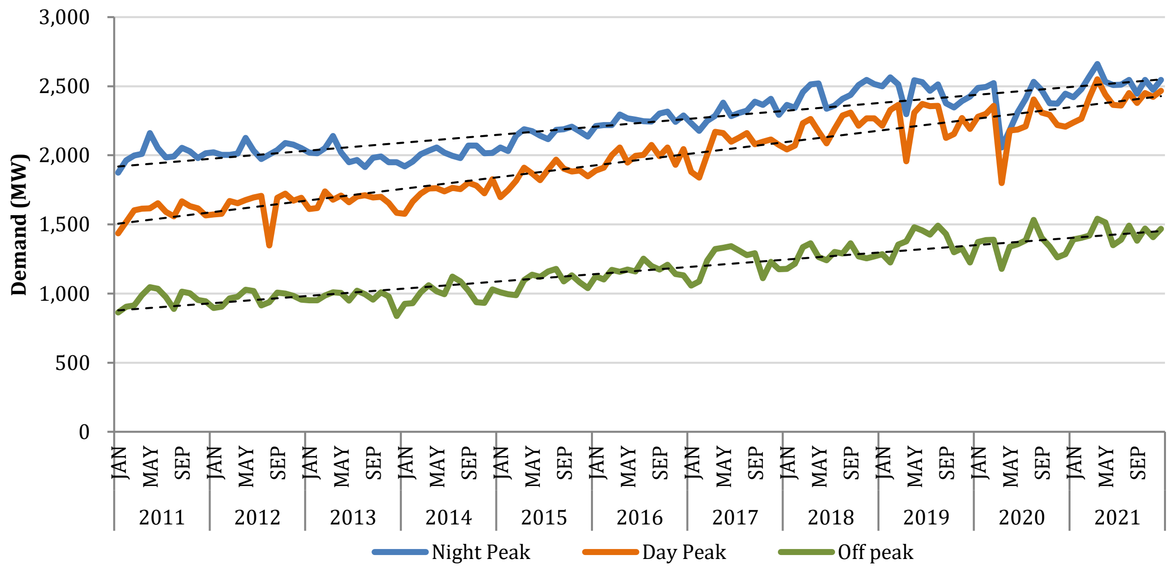


Figure 3.4 - Analysis of Night Peak, Day Peak and Off Peak Trends 2011-2021

According to the trend of peak growth, it is predicted that the night peak and day peak profiles would crossover around 2025. Annual day peak to night peak ratio for the study horizon was obtained by extrapolating the trendlines through this analysis which is used in developing load profiles for the study horizon as explained in Section 3.8. Typical daily load profiles for different day peak to night peak ratios are shown in Figure 3.5.

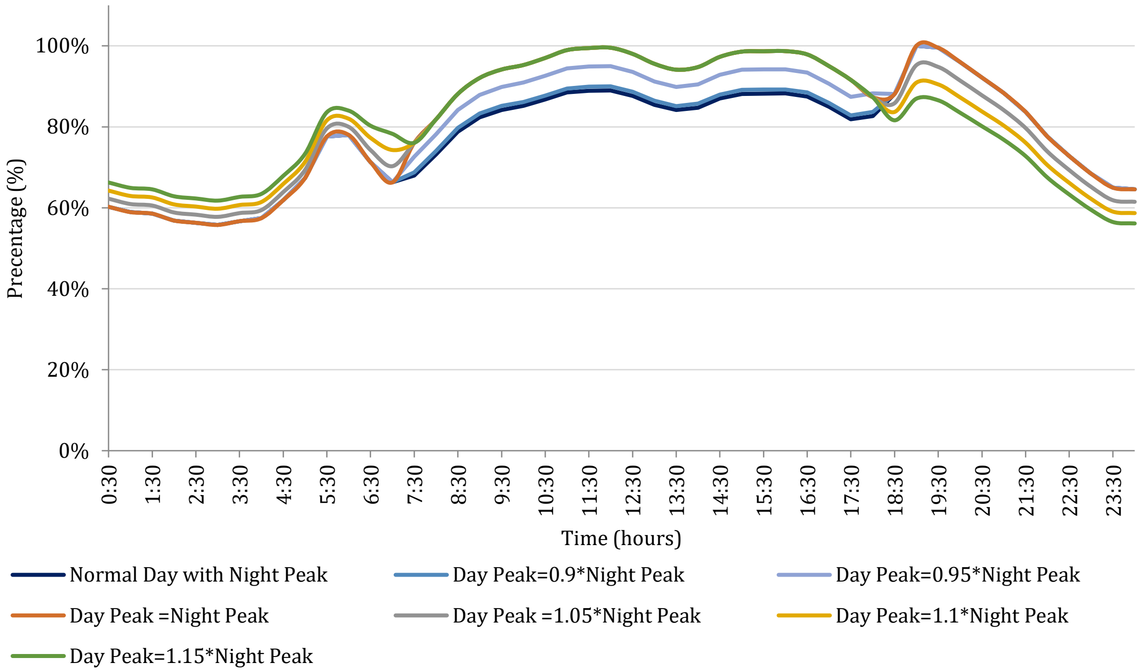


Figure 3.5 - Typical Load Profile Shape Forecast

Afterwards, the corresponding load factor for each typical day peak to night peak ratio was calculated based on the profile shapes in Figure 3.5. The forecast of annual load factor up to 2049 was done based on this analysis considering the relationship between the ratio of the day and night peak demands and the load factor.

In addition, growth of the off peak based on the past growth (as in Figure 3.4) is considered for the future. The forecasted system load factor[1] is expected to decrease slightly starting from 74% in 2025 to 72% in 2049 and stabilize. Finally, the peak demand forecast was derived using the annual net electricity generation forecast (obtained in section 3.4.5) and load factor forecast.

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[1] Presently the load factor forecast is based on historical demand data which considers the trend in demand pattern variations at the consumer end. Therefore, it captures the already prevalent trends of demand side management measures and other factors such as trends in installation of battery storage by customers and impact from implementation of TOU pricing. However potential impact of the forecasted variations to such driving factors has not been included due to unavailability of reliable data.
The intended operation pattern of energy storage systems including pumped storage power plant is an output of planning studies and hence has not been considered to derive the system load factor, which is an input. However, proposed energy storage systems will impact the final system load factor as observed in forecasted dispatches.

3.5 Base Demand Forecast 2025-2049

Base demand forecast 2025-2049 was prepared as per the methodology described in Section 3.4 for the planning horizon. Table 3.3 shows the 'Base Demand Forecast 2025-2049'.

Table 3.3 - Base Demand Forecast 2025-2049

Year	Demand[1]	Net Loss[2]	Net Generation		Day Peak		Night Peak
	GWh	%	GWh	Growth Rate (%)	MW	Growth Rate (%)	MW
2025	16,319	7.93	17,725	5.2	2,727	5.3	2,696
2026	17,203	7.76	18,650	5.2	2,872	5.3	2,824
2027	18,135	7.62	19,630	5.3	3,027	5.4	2,959
2028	19,118	7.48	20,662	5.3	3,190	5.4	3,101
2029	20,153	7.34	21,750	5.3	3,362	5.4	3,250
2030	21,245	7.34	22,927	5.4	3,548	5.5	3,411
2031	22,264	7.33	24,026	4.8	3,722	4.9	3,560
2032	23,329	7.33	25,174	4.8	3,904	4.9	3,714
2033	24,438	7.32	26,369	4.7	4,094	4.9	3,874
2034	25,602	7.32	27,624	4.8	4,294	4.9	4,041
2035	26,842	7.31	28,961	4.8	4,507	5.0	4,219
2036	28,188	7.31	30,411	5.0	4,738	5.1	4,412
2037	29,619	7.31	31,953	5.1	4,985	5.2	4,616
2038	31,141	7.3	33,594	5.1	5,247	5.3	4,833
2039	32,702	7.3	35,275	5.0	5,516	5.1	5,055
2040	34,338	7.29	37,038	5.0	5,798	5.1	5,286
2041	36,058	7.29	38,892	5.0	6,095	5.1	5,528
2042	37,798	7.28	40,767	4.8	6,397	4.9	5,772
2043	39,582	7.28	42,689	4.7	6,706	4.8	6,020
2044	41,424	7.27	44,673	4.6	7,026	4.8	6,275
2045	43,235	7.27	46,624	4.4	7,342	4.5	6,524
2046	45,062	7.26	48,592	4.2	7,660	4.3	6,773
2047	46,922	7.26	50,594	4.1	7,985	4.2	7,025
2048	48,732	7.25	52,544	3.9	8,303	4.0	7,267
2049	50,592	7.25	54,546	3.8	8,630	3.9	7,516
5 Year Avg Growth	5.4%		5.2%		5.4%		4.8%
10 Year Avg Growth	5.1%		5.1%		5.2%		4.6%
20 Year Avg Growth	5.0%		5.0%		5.1%		4.5%
25 Year Avg Growth	4.8%		4.8%		4.9%		4.4%

[1]In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.
[2] Net losses include losses at the Transmission & Distribution levels. Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

3.6 Development of Demand Forecast Scenario with Anticipated Electrical Vehicle (EV) Penetration

Sri Lanka being a signatory to Paris Agreement on Climate Change has taken several initiatives in policy level to reduce carbon emissions and reach carbon net zero goals along with Sustainable Development Goals (SDG).

When examining the emission statistics of Sri Lanka, it can be seen that transport sector contributes 51% of CO_2 emissions. Hence decarbonizing the transport sector is essential to realise environmental obligations as a nation. Replacing conventional fuel-based vehicles with Electric Vehicles (EVs) is the major means of decarbonizing the transport. Thus, strategical interventions to promote EVs such as regulating EVs, regulating electric vehicle (EV) charging stations, were in place for quite some time now, but there has not been a substantial progress.

In this background, the Ministry of Transport and Highways is in the process of formulating a national electric mobility (e-mobility) policy to popularise the use of EVs by systematic approach. Accordingly, a committee of sector experts under UNESCAP support prepared the draft report "Development of Policy Framework for EV Transition for Sri Lanka and Implementation Plan" [9], to streamline and expediate the transport sector decarbonization. With above developments, it became imperative to incorporate sufficient demand provisions to accommodate future Electric Vehicle (EV) charging requirements.

It should be noted that the demand of railway electrification projects which are reasonably definite to implement in future is considered under major projects and added to the base demand forecast appropriately.

According to the aforementioned final draft report in November 2023, three strategies of EV transition with different policy interventions are considered aligning with global transport energy consumption models.

i. **Business-as-Usual (BAU)** - This is closest to the Business-as-Usual (BAU) strategy, where future decarbonization is mostly left to market forces, while the current motorization trends continue. Public transport share is expected to reach 50% by 2050.
ii. **Moderate EV Penetration** - Assumes moderate level of policy interventions to improve public transport to achieve the target 50% public transport mode share by 2040, causing lower motorization.
iii. **Aggressive EV Penetration** - More aggressive policy on decarbonization, with corresponding reductions in motorization, aimed to achieve 50% public share by 2030.

Figure 3.6 shows the annual electricity requirement under each scenario. EV growth rate of the BAU scenario follows the present trend. Hence demand increase associated with future EV growth under BAU scenario is considered to be already captured in the demand forecast 2025-2049. In both moderate and aggressive EV penetration scenarios, demand of EV charging until 2028 is not significantly high compared to the BAU scenario. Hence, it could be assumed that any additional demand due to EV penetration under any of the three scenarios upto 2028 could be reasonably accommodated in the demand forecast 2025-2049. As it is too early to decide on the probability of actual realization of the targets any changes in actual EV penetration would be considered in future planning cycles once the arising of demand growth is reasonably certain.

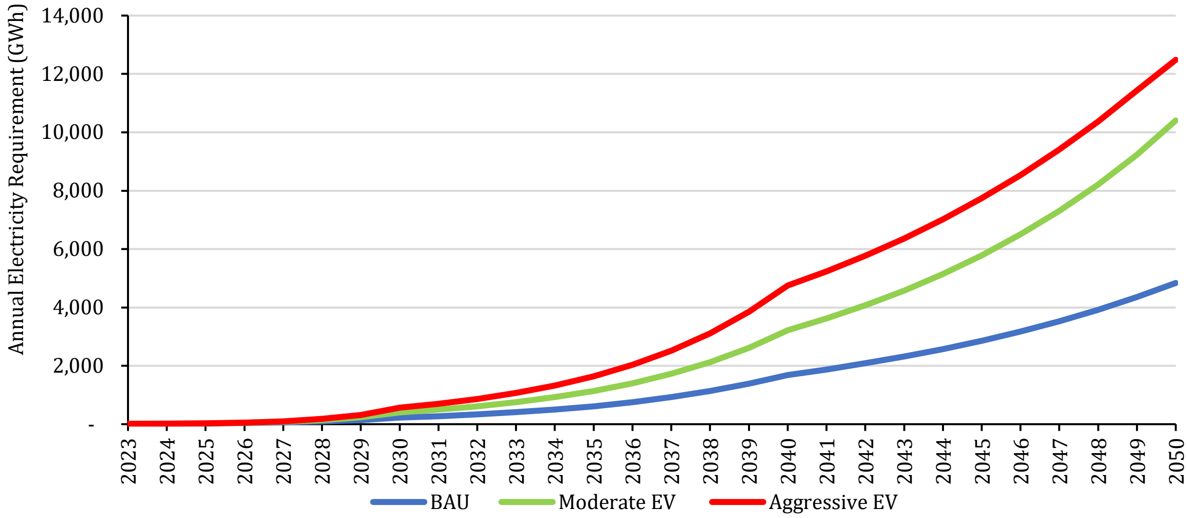


Figure 3.6 - EV Demand under each Scenario

If electrification of the transport sector is to be boosted as anticipated in the report, sizable additional demand will be added to the system after 2028. As mentioned in Figure 3.6, under moderate and aggressive EV scenarios, annual demand of EV charging would be 3,223 GWh and 4,751 GWh respectively in 2040 which is expected to be increased to 10,407 GWh & 12,485 GWh in 2050.

In the current planning cycle, in order to evaluate the additional generation requirement arising from actual realization of high EV penetration as presented in the report, a demand scenario was developed assuming the worst-case scenario in the demand forecast aspect, which is the aggressive EV penetration scenario.

3.7 Demand Forecast Scenarios

Different demand forecast scenarios were prepared considering variations to the base demand forecast as listed below. These scenarios (High, Low and Aggressive EV load forecast) were considered in evaluating the sensitivity of the load variation on the base case generation expansion plan are described in Chapter 10.

a) **High Load Forecast (Econometric)** - The forecast developed considering higher economic growth of the country considering the GDP growth rate projections by CBSL annual report, 2023. This growth rates were assumed considering that country would reach a level shift in the economy and gradually reach saturation of GDP growth towards the end of the planning horizon. This scenario is considered the most optimum scenario.

b) **Low Load Forecast (Econometric)** - The forecast developed considering economic growth rate reduction compared with annual growth rate considered for the base load forecast (slow recovery of the economy considered for the initial years) and also reduction of other driving factors.

c) **Long Term Time Trend Forecast** - The forecast developed purely based on the time trend approach using the past 25 year electricity demand figures starting from 1998.

d) **Aggressive EV Penetration** – The projection assumes a low carbon development pathway with more aggressive policy on decarbonization, with corresponding reductions in motorization, aimed to achieve 50% public share by 2030.

Annual demand forecast of the above scenarios are presented in Annex 3.1. Figure 3.10 & Figure 3.11 shows graphically, the electricity net generation and peak load forecast for the above four scenarios including Base Load Forecast.

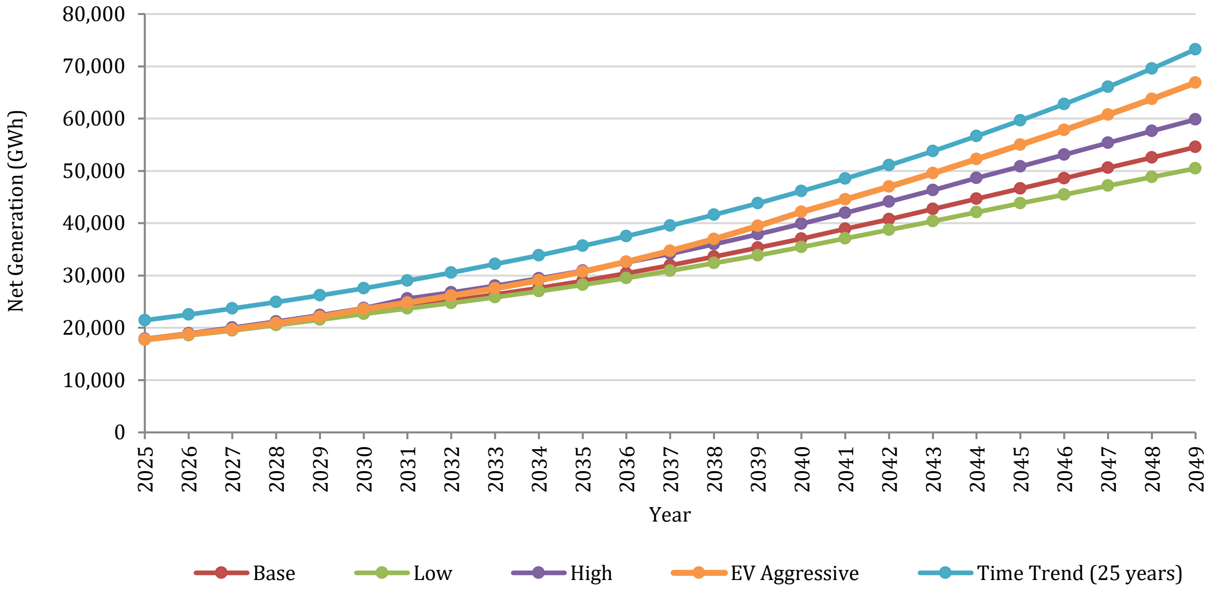


Figure 3.7 - Generation Forecast Comparison of Scenarios

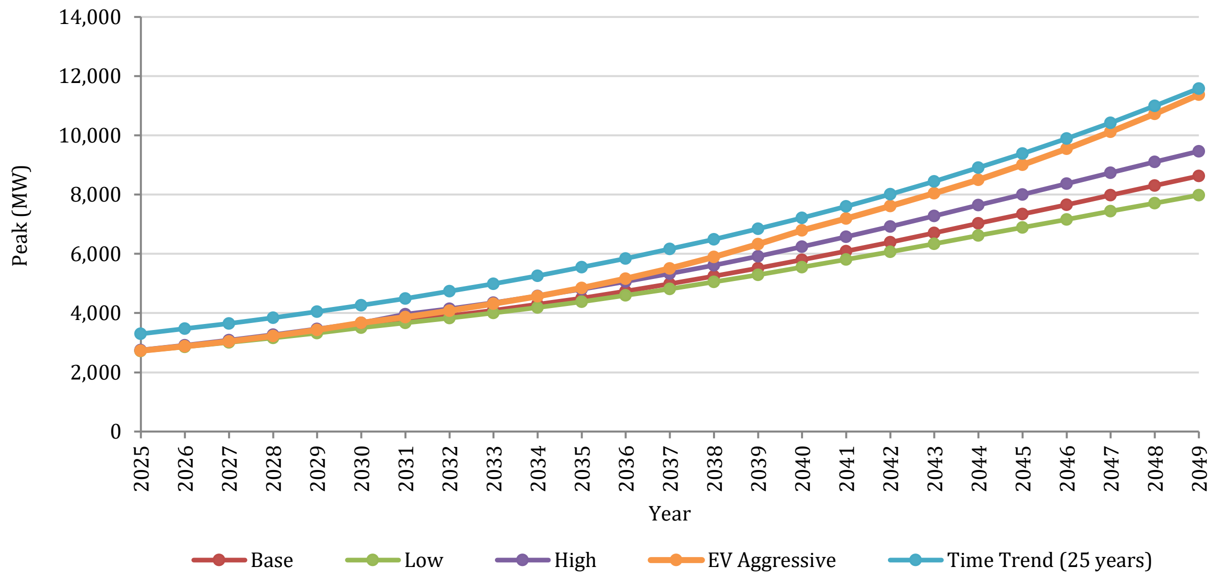


Figure 3.8 - Peak Forecast Comparison of Scenarios

3.8 Development of Hourly load Profiles

To carry out hourly dispatch simulations during long term generation expansion planning process, it is necessary to develop hourly load profiles of the base demand forecast for study horizon from 2025 to 2049. Usually, generation profile of the most recent year is considered as the base year in order to derive this. Since there were continuous load shedding during the year 2022, generation profile of the year 2021 was taken as the most appropriate representation to be considered as the base year.

Generation profile which was obtained from national system control center was adjusted to capture the rooftop solar self-consumption and any other renewable power plants which are not metered in real time. This adjustment is carried out based on estimated renewable resource profiles used for planning studies. A sample week (Monday to Sunday) of the adjusted generation profile in year 2021 in hourly resolution (dispatch simulations are carried out in SDDP software in hourly resolution) is shown in Figure 3.9.

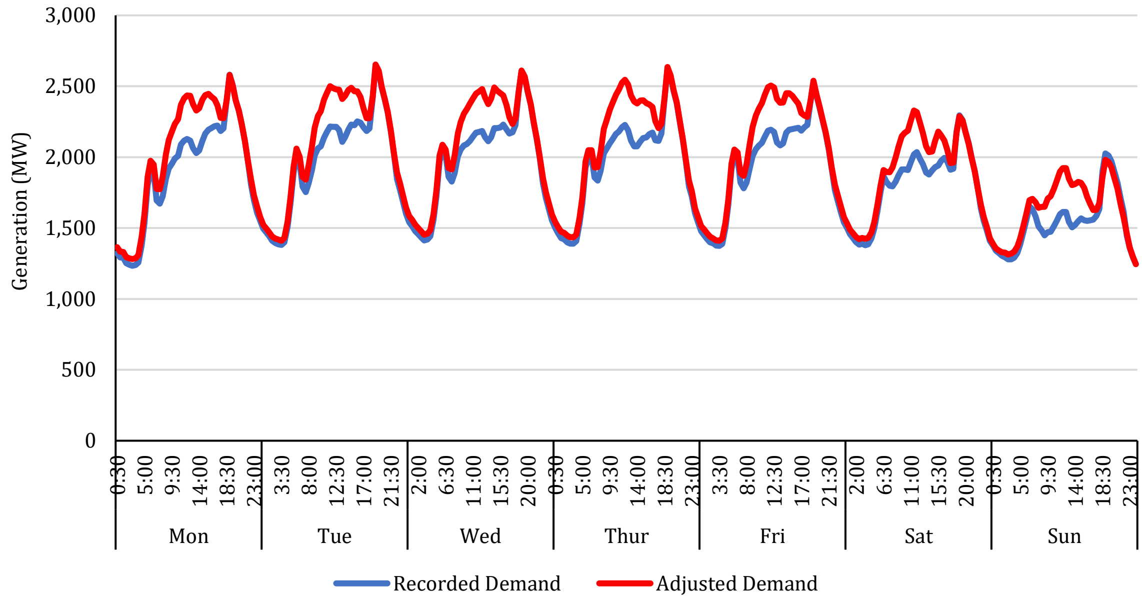


Figure 3.9 - Sample Week of Base Year 2021

After obtaining the base year generation profile, this profile is adjusted to match the parameters of the 25 years (Table 3.3) of the study horizon to obtain hourly generation profiles for each year of the whole study horizon. In this process, annual net generation, day peak and night peak demand, off-peak demand were appropriately considered. Figure 3.10 shows the sample of generation profiles developed in above manner for the sample week shown in Figure 3.9. These hourly profiles are an input to the SDDP software.

Similarly, hourly generation profiles were obtained for the high load forecast and low load forecast scenarios as well. For the aggressive EV penetration scenario, the annual additional demand was considered as a flexible demand to obtain a more economical charging profile through the optimization using SDDP software. The actual charging profile may differ based on the nature of the policy interventions made during the process of transition to e-mobility.

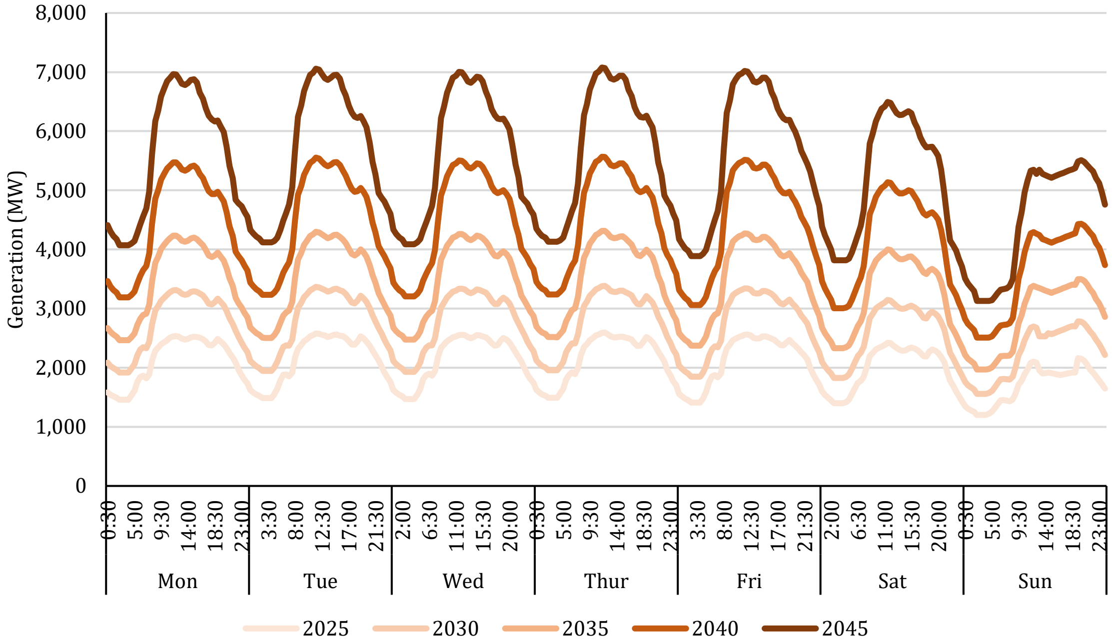


Figure 3.10 - Sample Weekly Generation Profile for Selected Years

3.9 Comparison with Past Forecasts

Electricity demand forecast is reviewed once in two years with the revision of Long Term Generation Expansion Plan. This enables to capture the latest changes in the electricity demand as well as associated socio-economic factors. Table 3.4 shows the comparison of past demand forecasts used in the previous expansion plans and their percentage variation against the gross energy sold in respective years. Electricity demand forecast is determined based on information considering:

a) National economic development
b) National population growth
c) Increase in number of electricity consumer account
d) Increase of per capita income, etc.

The under achievement or over achievement of above facts will contribute to negative or positive deviation in actual demand from the forecast.

Table 3.4 - Comparison of Past Demand Forecast with Gross Energy Sold

Year	LTGEP 2013 - 2032	LTGEP 2015 - 2034	LTGEP 2018-2037	LTGEP 2022-2041	LTGEP 2023-2042	Gross Sales (GWh)
2012	10,675 (+1.9%)					10,474
2013	11,104 (+4.5%)					10,624
2014	12,072 (+9.1%)					11,063
2015	12,834 (+8.9%)	11,516 (-2.3%)				11,786
2016	13,618 (+6.5%)	12,015 (-6.0%)				12,785
2017	14,420 (+7.4%)	12,842 (-4.4%)				13,431
2018	15,240 (+8.2%)	13,726 (-2.6%)	14,588 (+3.5%)			14,091
2019	16,075 (+10.0%)	14,671 (+0.4%)	15,583 (+6.7%)			14,611
2020	16,937 (+18.6%)	15,681 (+9.8%)	16,646 (+16.5%)			14,286
2021	17,830 (+17.2%)	16,465 (+8.2%)	17,478 (+14.9%)			15,214
2022	18,754 (+29.2%)	17,288 (+19.1%)	18,353 (+26.4%)	16,741 (+15.3%)		14,520
2023	19,713 (+39.3%)	18,155 (+28.3%)	19,273 (+36.2%)	17,705 (+25.1%)	16,741 (+18.3%)	14,153

Within bracket figures indicate the percentage deviation of demand forecast with reference to gross energy sold. Demand forecast represent actual electricity energy demand of the country considering energy not severed and rooftop solar self-consumption. Hence the error shown here is overestimated.

3.10 Electricity Demand Reduction and Demand Side Management

Energy demand reduction is taken as a key alternative in the design of energy supply schemes, as it is another way of balancing the energy demand with available supply, as opposed to building new facilities to cater to increasing demand. Demand Side Management (DSM) is a set of activities, which encourage consumers to modify their level and pattern of electricity usage. DSM refers not only to energy reduction but also for load shifting, peak shaving etc. which will help to change load profiles to constant flat load curves by allowing more electricity to be provided by less expensive base load generation. Ultimately, these initiatives will avoid peak demand burden on the network by supporting efficient utilization of available generating options.

Improving Energy Efficiency and Conservation is identified as one of the ten pillars of the National Energy Policy and Strategies (NEPS) of Sri Lanka, 2019. These efforts will reduce the overall cost of energy to the consumer while saving valuable resources of the country and reducing the burden on the environment. Therefore, demand reduction and demand side management will be an important thrust in the foreseeable future. Efficient use of energy will be promoted in all sectors and across the energy value chain, engaging both the suppliers and users, even extending the services to newer markets such as transport and agriculture.

The NEPS identified several strategies on energy demand reduction impacting many sectors in the demand side. Accordingly, identified main strategies which are directly and indirectly related to the power sector are as follows:

a) Further strengthening of the national energy efficiency improvement and conservation programme engaging all stakeholders in household, industrial and commercial sectors.
b) Energy efficiency improvement and conservation will be promoted through minimum energy performance standards and labelling of appliances, and by introducing green procurement processes in state and private sector organisations.
c) Taxation and other incentives and disincentives to support the market for efficient technologies will be introduced.
d) Expert energy advisory services will be offered through state and private sector service providers to promote energy efficiency, conservation and energy cost reduction across all end use sectors.
e) Water resources will be recognized as a valuable indigenous energy resource. Efficient use of water by competing users at places where there is a high opportunity cost to water will be enhanced.
f) Conversion efficiency of power generation facilities will be enhanced.
g) A strategic plan for street lighting will be formulated to ensure proper management of street lighting.
h) Automated demand response technologies will be considered as a main demand-side management strategy.
i) Losses in energy delivery networks will be reduced to optimum levels.
j) Virtual offices and video/teleconferencing will be promoted by making necessary changes to organisational working culture as a strategy to minimize physical movement.
k) Energy efficiency will be a primary concern in retrofits, and new building designs will be evaluated for their energy performance on a mandatory basis.
l) Smart technologies, including smart buildings and complete conversion to smart metering will be ensured to convey price signals to customers, altering the demand profile to reduce the overall cost of supply.

Sustainable Energy Authority (SEA) which carries the responsibility of designing and implementing the energy efficiency improvement and conservation programme, succeeded in raising a USD108 million concessionary loan from the World Bank / Green Climate Fund sources, targeting the commercial sector energy efficiency improvement. Due to repurposing of the World Bank finances in response to the economic crisis, the facility could not be deployed as planned in 2022.

Some of the candidate concepts for reducing energy demand identified by the SEA deals with appliance labelling, efficient chillers, efficient motors and variable speed drives, energy efficiency building code, smart homes and power factor improvement continued under the auspices of the SEA.

SEA managed to deploy several major programmes on energy efficiency improvement and conservation. A brief summary of the initiatives taken by SEA is given below:

Financing Energy Efficiency: The Authority has approached international lenders to relaunch the lending programme developed in association with the World Bank and the Green Climate Fund (GCF).

Chiller Survey: A survey was conducted to get a broad picture of the chiller population in the country and to establish a database of their capacities, age, efficiency, etc. The Authority managed to compile an inventory close to a thousand installations of large chillers in the country. The energy audits carried out on a sample of this inventory revealed that there is a substantial opportunity to realise energy savings by replacing aging chillers.

Efficient Refrigerator Programme: This is a scheme of replacing old inefficient refrigerators with efficient Minimum Energy Performance (MEP) labelled refrigerators in households. The pilot project revealed a considerable potential to save energy by a refrigerator exchange programme, as a third of the refrigerators evaluated were found to be operating with energy waste.

Establishment of Energy Consumption Benchmarks: The main objective of this project is to facilitate the energy conservation in commercial, industrial and government sectors through long-term programmes such as the Energy Manager programme, Energy Auditor programme, establishing energy consumption benchmarks, etc. The Energy Consumption Benchmark Regulation was enforced in mid 2023, covering the financial services sector and the retail food outlets, involving more than 10,000 end use facilities.

Enforcing the Code of Practice for Energy Efficient Buildings: The main objective of the Energy Efficiency Building Code (EEBC) is to improve the energy performance of large-scale buildings such as commercial buildings, industrial facilities and large-scale housing establishments. EEBC was finalized by the end of 2021, printed and disseminated among the stakeholders. The draft regulation approved by the Board was referred to the Urban Development Authority to iron out any implementation issues and a consensus was reached between the two Authorities on implementation modalities. The amended draft regulation has been sent to the Department of Legal Draftsman for further scrutiny.

Energy Labelling Programme for Appliances: Dissemination of energy efficient appliances in the market is very important in order to reduce energy demand in the country. Yet energy efficiency is not an information revealed by the product suppliers and hence customers do not have an opportunity to select energy efficient products during purchasing of energy using appliances. Through the appliance energy labelling programme energy labels which display the energy efficiency of products in a simple manner, facilitate customers to select energy efficient products during purchasing. At present mandatory energy labelling schemes are in operation for Compact Fluorescent Lamps (CFLs), Ceiling Fans (swept dia: 1400 mm), LED lamps and Refrigerators. With the establishment of test facilities for room air-conditioners and water pumps, these equipment too will come under the mandatory programme by the end 2024. It is planned to extend the energy labelling programme for LED panels, televisions, rice cookers, gas stoves, pedestal, table and wall fans, washing machines, electric cookers and electric heating devices by preparing and publishing standards in the medium term.

Consumer Education: The syllabus of the science subject is presently being improved based on the inputs of the sustainable energy from the Authority. 101 fun filled student activities were introduced to the curriculum to make sustainable energy, an appealing topic to the students of Grades 7-11.

Study on Suitable Technologies for Street Lighting: This programme is designed to improve the street lighting system in Sri Lanka with the coordination of CEB, LECO, urban councils, municipal councils and Pradeshiya Sabhas. It is intended to prepare a set of specifications for street lights as an outcome of this programme. A pilot project to upgrade a street lamp system is being implemented in Divulapitiya area. Valuable information pertaining to actual energy saving potential of street lamp modification is expected from this pilot project.

Survey of Household Appliances: The sample survey involving 6,430 households carried out with the support of the Department of Census and Statistics provided some key results in the preliminary data analysis reports, giving a good understanding of the household energy use. The draft report prepared by the Authority is now under the review of the Department of Census and Statistics.

Accordingly, following activity plan has been prepared by SEA which is the responsible agency for implementation of DSM activities. Annual estimated savings until 2030 are given in Table 3.5 and the reduction could be mainly expected on daytime for these activities.

Table 3.5 - DSM Implementation Plan

DSM Initiative	**Annual Estimated Savings (GWh)**						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Energy Efficiency Building Code	-	10	20	30	60	60	60
Appliance Energy Performance Labelling Programme	170	135	170	190	210	245	260
Efficient Refrigerator Replacement Programme	0.5	3.5	18	35	35	35	35
Establish energy benchmarks for industrial and commercial sectors	98	257	444	582	640	704	775

The formidable barriers to implementation of the DSM programme should be further analysed with associated costs, to gain a better understanding of the benefits and costs of the programme. In addition, in the present mode of implementation, utilities do not have a proper control over the implementation of DSM as it will depend on consumer attitudes, best moulded through strict Government policies including fines on wasteful consumption of electricity. With the subsidies given to the electricity sector in different categories, ensuring deterministic demand reduction may not be realistic. Therefore, the DSM forecast having high speculative public response dependent demand reduction should not be considered in determining of the future expansion plan and medium term time trend forecast model will capture the recent year trends including the impact on present DSM activities. On the other hand, interventions with little or no room for human response factors, ranging from automated demand response technologies to large scale plant improvement investments can be taken into future planning exercises, as they are proven to provide very predictable demand reductions and energy savings.

CHAPTER 4
THERMAL POWER GENERATION OPTIONS FOR FUTURE EXPANSION

4.1 Background

Power generation options are broadly categorized into 'renewable energy based power generation' and 'thermal energy based power generation'. Thermal energy based power generation technology types are of internal combustion engines, gas turbines, steam turbines and combined cycles utilizing fuel combinations of oil, natural gas and coal. Nuclear power generation also falls into thermal power generation where nuclear fuel is used to operate a steam turbine.

Thermal power generation has its benefits as well as distinct drawbacks compared to its alternative, renewable power generation. Each technology has its specific operational characteristics as well as economics. A large number of factors including cost of development, O&M costs and operational constraints have to be evaluated while adhering to environmental limitations in order to consider the suitability of these primary generation options. The costs of associated environmental mitigation measures of respective generation options are included in the cost figures given in this report.

Several studies had been conducted to assess the future thermal options for electricity generation in Sri Lanka. These studies include:

a) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka, 2010 [10].
b) Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka, 2014 [11]
c) Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka, 2014. [12]
d) Feasibility Study on High Efficiency and Eco-friendly Coal-fired Thermal Power Plant in Sri Lanka, 2015 [13]
e) Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka, 2018. [8]

4.2 Thermal Power Candidate Technologies

4.2.1 Thermal Power Technologies

The main categories for thermal power development technologies are based on Internal combustion engines, gas turbines, steam turbines and combined cycles.

Internal combustion Engines

Internal combustion engines are typically categorized by speed and fuel type. They come in fuel forms of gaseous fuel, liquid fuel, and dual fuel. Due to the possibility of adopting modular sizes of these engine technologies, higher degree of flexibility is seen in operation. In addition, it provides favourable fuel efficiency merits in part load operations with fast start up times. However, the inertia support from internal combustion engines is low.

Simple Cycle Gas Turbines

Gas turbine can operate from both gaseous fuel and liquid fuels. They are classified into two main categories; aero derivative gas turbines and industrial gas turbines. Both of these find application in the power generation industry, for peaking and fast load balancing applications. Simple cycle gas turbines have faster start up times and quick ramping capabilities while aero-derivatives have additional advantages of higher efficiency, no additional cost on O&M for the startup and less maintenance downtime. Gas turbines provide high rotating inertia which is essential for power system stability.

Combined Cycle Gas Turbine

Combined cycle gas turbine plants consist of gas turbine (GT), heat recovery steam generators (HRSG) and steam turbine (ST). There are many different configurations but most common are 1x1x1 and 2x2x1. As common practice, the HRSG is tailored specifically for each gas turbine unit but there are also configurations where 2 or more gas turbines are connected to a single HRSG (2x1x1). Combined cycle plants are often characterized with very high efficiencies designed for baseload and intermediate load operations.

Steam Turbines

Steam turbines are one of the most conventional technologies to produce electricity. Steam is produced by firing boilers, with the help of using fuels such as coal, nuclear and biomass. Steam turbines do not easily adapt to excessive load variations, therefore, are better suited for base load operation. However advanced designs in once through boiler technologies enable certain level of flexibility for operation of coal power plants.

4.2.2 Candidate Thermal Power Plant Specifications

A list of power generation technologies with different fuel configurations were considered as candidate thermal power plants in the planning studies. These were based on prevailing models in the market and previously conducted feasibility studies.

A summary of the capital costs and economic lifetimes of candidate plants taken as input to the present studies is given in Table 4.1. Capital costs of projects are in two components: The foreign cost and the local cost. During the prefeasibility and feasibility studies, capital costs have been estimated inclusive of insurance and freight for delivery to site (CIF basis). Local costs, both material and labour, have been converted to their border price equivalents, using standard conversion factors. No taxes and duties have been added to the plant costs. Whenever results of the project feasibility studies were available, these were adopted after adjusting their cost bases to reflect January 2024 values. No escalation is applied to capital costs during the study period, thus assuming that all capital costs will remain fixed in constant terms throughout the planning horizon.

In order to comply with the government policy target of achieving the carbon neutrality by 2050, hydrogen fired power plants and combined cycles with Carbon Capture Storage (CCS) also considered during this iteration of the planning cycle. Since 100% hydrogen fed power plants are not yet commercially available, 25% to 30% hydrogen blended fuel fed power plants are considered as candidate options.

Table 4.1 - Cost Details of Thermal Expansion Candidates

Plant	Pure Unit Cost (USD/kW) 2024	Construction Period (Years)	Total Unit cost with IDC @10% net) (USD/kW)	Economic life (Years)	Fixed O&M cost (USD/kW Month)	Variable O&M cost (USD/ MWh)
50 MW NG IC Engine	935	1.5	996	20	3.25	6.31
50 MW FO IC Engine	1,124	1.5	1,198	20	3.25	6.31
50 MW Dual fuel IC Engine	1,149	1.5	1,224	20	3.25	6.31
100 MW NG IC Engine	872	1.5	929	20	3.25	6.31
100 MW FO IC Engine	1,062	1.5	1,131	20	3.25	6.31
100 MW Dual fuel IC Engine	1,087	1.5	1,158	20	3.25	6.31
200 MW NG IC Engine	810	1.5	863	20	3.25	6.31
200 MW FO IC Engine	1,000	1.5	1,065	20	3.25	6.31
200 MW Dual fuel IC Engine	1,025	1.5	1,091	20	3.25	6.31
50 MW NG Gas Turbine	709	1.5	755	20	0.64	4.99
50 MW NG Gas Turbine (Aero)	847	1.5	902	20	1.48	5.21
100 MW NG Gas Turbine	525	1.5	560	20	0.64	4.99
100 MW NG Gas Turbine (Aero)	636	1.5	678	20	1.48	5.21
200 MW NG Gas Turbine	430	1.5	458	20	0.64	4.99
300 MW NG Gas Turbine	360	1.5	383	20	0.64	4.99
200 MW NG Combined Cycle	1,507	3	1,711	30	1.13	2.83
300 MW NG Combined Cycle	1,400	3	1,590	30	1.13	2.83
400 MW NG Combined Cycle	1,325	3	1,504	30	1.13	2.83
500 MW NG Combined Cycle	1,273	3	1,445	30	1.13	2.83
300 MW High Efficient Coal Plant	1,982	4	2,349	30	3.75	4.99
600 MW Super Critical Coal Plant	2,132	4	2,527	30	3.75	4.99
600 MW Nuclear Power Plant	5,103	5	6,316	40	11.18	2.63

All costs are in December 2023 border prices, IDC = Interest during Construction

Apart from the above candidates, combined cycles with Carbon Capture Storage (CCS) and Hydrogen blended power plants (Gas turbines, Combined cycles and IC Engine power plants) were considered beyond year 2035. The CCS technology cost is considerably higher compared to other alternate options. The respective cost figures for each technology were derived based on the OEM data available at time of preparing the document.

Operating characteristics of these plants are shown in Table 4.2.

Table 4.2 - Characteristics of Candidate Thermal Plants

Plant	Net Capacity[1] (MW)	Min Load (MW)	Heat Rate[2] (kcal/kWh) Full	Heat Rate[2] (kcal/kWh) min	Full Load Efficiency (Net, HHV) %	FOR[3] %
50 MW NG IC Engine	54	1	1,987	2,647	43.3	10.0
50 MW FO IC Engine	59	1	2,086	2,681	41.3	10.0
50 MW Dual fuel IC Engine	47	2	2,067	2,746	41.7	10.0
100 MW NG IC Engine	108	1	1,987	2,647	43.3	10.0
100 MW FO IC Engine	108	1	2,086	2,681	41.3	10.0
100 MW Dual fuel IC Engine	106	2	2,067	2,746	41.7	10.0
200 MW NG IC Engine	205	1	1,987	2,647	43.3	10.0
200 MW FO IC Engine	206	1	2,086	2,681	41.3	10.0
200 MW Dual fuel IC Engine	200	2	2,067	2,746	41.7	10.0
50 MW NG Gas Turbine	41	16	2,921	3,798	29.5	8.0
50 MW NG Gas Turbine (Aero)	49	25	2,377	3,091	36.2	8.0
100 MW NG Gas Turbine	106	53	2,469	3,312	34.9	8.0
100 MW NG Gas Turbine (Aero)	128	64	2,337	3,134	36.9	8.0
200 MW NG Gas Turbine	192	77	2,489	3,595	34.6	8.0
300 MW NG Gas Turbine	287	66	2,307	3,332	37.3	8.0
200 MW NG Combined Cycle	206	95	1,755	2,457	49.1	8.0
300 MW NG Combined Cycle	289	115	1,751	2,451	49.2	8.0
400 MW NG Combined Cycle	440	176	1,581	2,215	54.5	8.0
500 MW NG Combined Cycle	535	213	1,557	2,180	55.3	8.0
300 MW High Efficient Coal Plant	270	135	2,241	2,547	38.4	3.0
600 MW Super Critical Coal Plant	564	338	2,082	2,246	41.4	3.0
600 MW Nuclear Power Plant	552	497	2,685	2,723	32.1	0.5

[1] Refers to the net capacity of selected model representing the candidate plant
[2] Heat values of petroleum fuel and coal based plants are in HHV
[3] FOR = Forced Outage Rate

4.2.3 Thermal Power Plant Extensions

In order to find out the economic benefits by extending the lifetime of retiring plants, the possibility of lifetime extensions of following power plants were considered. The refurbishment cost required for such extensions were obtained from the respective OEM of each plant. Details about the refurbishments are presented in Table 4.3.

Table 4.3 - Details of the Power Plant Extensions

Plant	Extended life (years)	Required Cost (M USD)
Sapugaskanda PS A	5	8.8
Sapugaskanda PS B	5	16.4
Barge Mounted Power Plant	5	4.4

4.3 Fuel Types & Fuel Prices Considered for Analysis

Petroleum based fuels, coal, natural gas being the primary sources of fuel, were considered for this long term power generation expansion plan. Additionally, nuclear fuel was considered under the present context considering technical constraints. With the aim of going towards carbon neutrality, hydrogen is also emerging as a clean fuel technology which can be used to operate thermal plants.

Considering the high volatility present in fuel prices, constant fuel prices are mainly used in long term planning studies. The fixed prices in constant terms based on future projections by World Bank in "World Bank Commodity Price Forecasts – October 2023" was used for this planning study as recommended by the PUCSL. All fuel prices considered are in economic terms, exclusive of taxes.

4.3.1 Liquid Petroleum Products (Auto Diesel, Fuel oil, Naphtha)

In the present context, all fossil fuel based thermal generation in Sri Lanka would continue to depend on imports. Ceylon Petroleum Corporation (CPC) presently provides all petroleum products required for thermal power stations. Furthermore, oil exploration activity is presently ongoing in the Mannar basin.

The average of crude oil CIF price to Sri Lanka from year 2020 to 2023 is 71.1 USD/bbl which is in line with the Brent Crude Oil index for the same period. The rapid increase observed in fuel prices due to global economic crisis in the initial months of 2022 has reduced but higher than pre crisis prices.

The comparison of actual historical crude oil CIF price to Sri Lanka with World Bank fuel price forecast (October, 2023) is shown in Figure 4.1. The crude oil price was derived based on future fuel price projections by World Bank is 80.7 USD/bbl. A fuel price sensitivity scenario is modelled in Section 8.4 to capture the implications of long term international price forecasts.

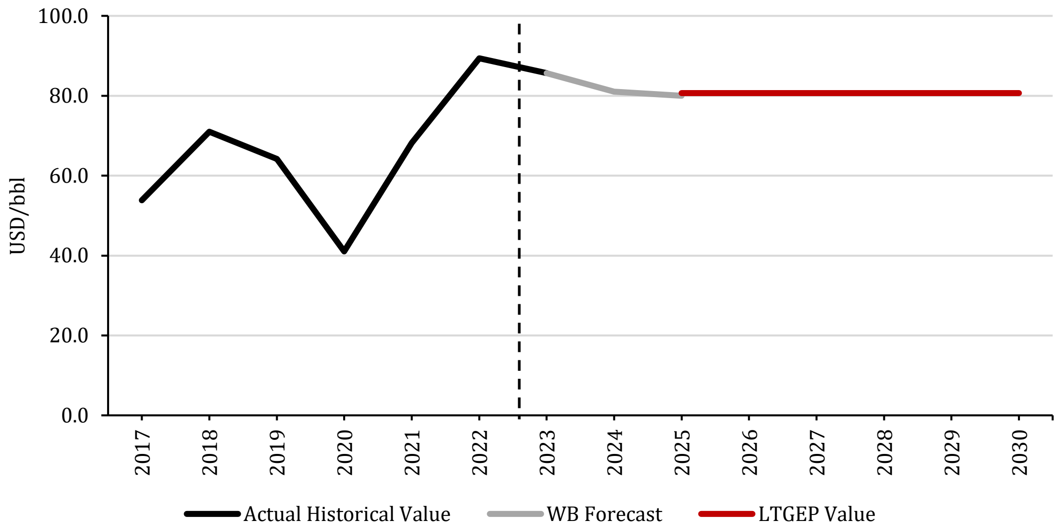


Figure 4.1 - Crude Oil Price Estimation for Analysis in LTGEP

Based on future projections by World Bank and average value of the economic prices provided by the CPC, the fuel prices for diesel, fuel oil and naphtha are derived for LTGEP 2025-2044. The CIF prices are shown in Table 4.4 with the fuel characteristics and the fuel prices used in the analysis.

For each fuel type, the applicable local cost were separately added. Further, all the heat contents given are based on Higher Heating Value (HHV).

Table 4.4 - Oil Prices and Characteristics for Analysis

Fuel Type	Heat Content (kcal/kg)	Specific Gravity (kg/l)	CIF Price ($/bbl)
Auto Diesel	10,500	0.84	112.2
Fuel oil	10,300	0.94	116.7
Naphtha	10,880	0.65	86.1

Source: Oil prices based on Ceylon Petroleum Corporation

4.3.2 Coal

Coal is a common fuel option for electricity generation in the world. Coal prices vary with the specific calorific value of coal and other specific parameters of the coal quality such as Ash content, Sulphur amount and volatility. Coal procured to Sri Lanka at present is based on the API 4 index from Argus which is correlated to the coal of net heat value of 6,000 kcal/kg on FOB basis from Richards Bay, South Africa. Shipping cost which was around 15 USD/MT before the economic crisis has significantly increased and in recent years it has reached around 25 USD/MT.

The coal price derived based on future fuel price projections by World Bank, including the handling charges as recommended by PUCSL is 133 USD/MT.

The derived coal price for LTGEP 2025-2044 (without handing charges) compared with coal fuel price forecast by World Bank (October, 2023) and the historical coal prices which are based on coal from New castle, Australia is shown in Figure 4.2. Future projections by the World Bank for Australian coal and the historical coal prices from Australia and South Africa was considered in deriving coal price for LTGEP 2025-2044. A fuel price sensitivity scenario is modelled in Section 8.4 to capture the implications of long-term international price forecasts.

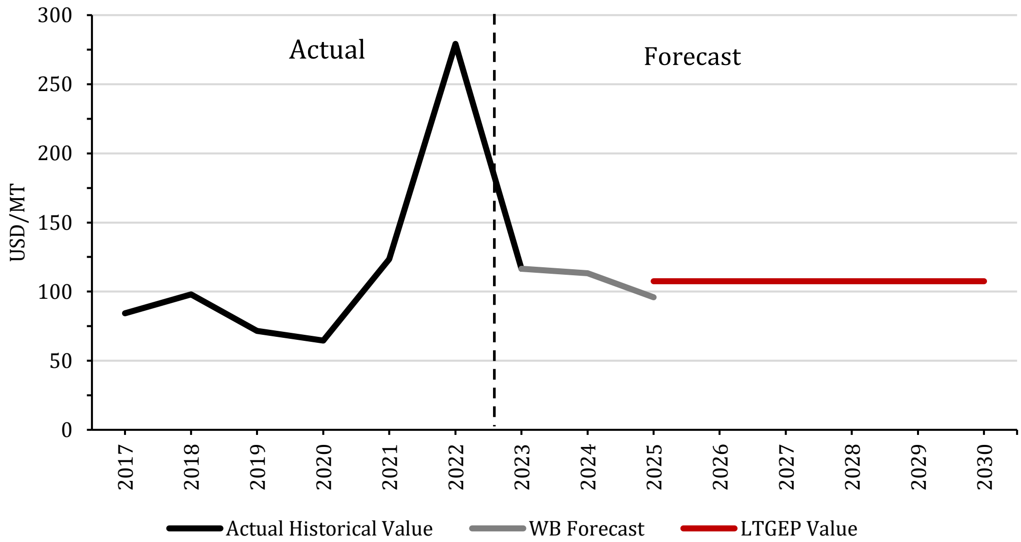


Figure 4.2 - Coal Price Estimation for Analysis in LTGEP

4.3.3 Natural Gas

Natural gas would add diversification to the country's fuel mix. There is no commercially developed gas field in Sri Lanka though discoverable gas reserves have been identified. Natural Gas as a fuel for Gas Engines, Gas Turbine and Combined Cycle plants is an attractive option from environmental perspective as it is having relatively low carbon emission.

4.3.3.1 Regasified Liquefied Natural Gas

Feasibility study for introducing LNG to Sri Lanka that was conducted in year 2014, has identified the Colombo North Port as the best site for development of a LNG terminal out of several promising candidate sites including Hambantota and Trincomalee. LNG requirement of the country was determined considering the fuel conversion possibilities of the existing combined cycle power plants located in Colombo and other sectors such as Industrial and Transport sectors. The study has also identified Kerawalapitiya as the most suitable location for the development of new NG fired power plants by considering the technical, economic, social and environmental aspects. As identified therein, LNG facility suitable for Sri Lanka would have a land based storage, regasification unit and necessary piping structures with a properly established LNG importing mechanism (via tanker ships).

The recent development of Floating Storage and Regasification Unit (FSRU) which can be moored in the sea has faster implementation possibility than a land based storage structure and is found to be less capital intensive. Considering the initial requirements identified in previous planning studies, CEB has initiated procurement process for the deployment of a FSRU and mooring system, offshore of Kerawalapitiya with a regasification capacity of 375 MMSCFD and LNG storage capacity of minimum 156,000 m3. The terminal is expected to operate for a period of 10 years on BOO basis whereas the Mooring System on BOOT basis. Pipeline infrastructure up to the boundaries of the power plants will be established by Ceylon Petroleum Corporation on BOOT basis.

LNG prices are categorized based on long term contracts, medium term contracts and short term spot prices. There are different LNG pricing mechanisms adopted in different regions of the world. The long term contracts are often linked with oil price and in the Asian market, Japanese Crude Oil Cocktail (JCC) and Brent Crude Oil Index is used for this purpose. Platts Japanese Korean Marker (JKM) is another benchmark price for the Asian region. In addition, LNG contracts based on Henry Hub prices are also considered for Long Term and Medium Term Contracts.

The average LNG price from year 2020 to 2023 based on Brent Crude Oil Index is, 9.6 USD/MMBtu The Henry Hub Index based average LNG Price for the same period is 8.2 USD/MMBtu (linked to Henry Hub Crude Oil Index with formula 1.15%*HH+ 4).

The historical LNG price based on Brent Crude Oil Index, forecast of World Bank fuel price (October, 2023), and the LTGEP derived value based on World Bank forecast is shown in Figure 4.3. The CIF price of LNG based on the future price projections by the World Bank (including handling charges), 11.2 USD/MMBtu is used in LTGEP 2025-2044. Operational cost component of handling charge is only considered in the deriving this value and the capital cost associated in LNG infrastructure is excluded. A fuel price sensitivity scenario is modelled in Section 8.4 to capture the implications of long term fluctuations of international LNG price.

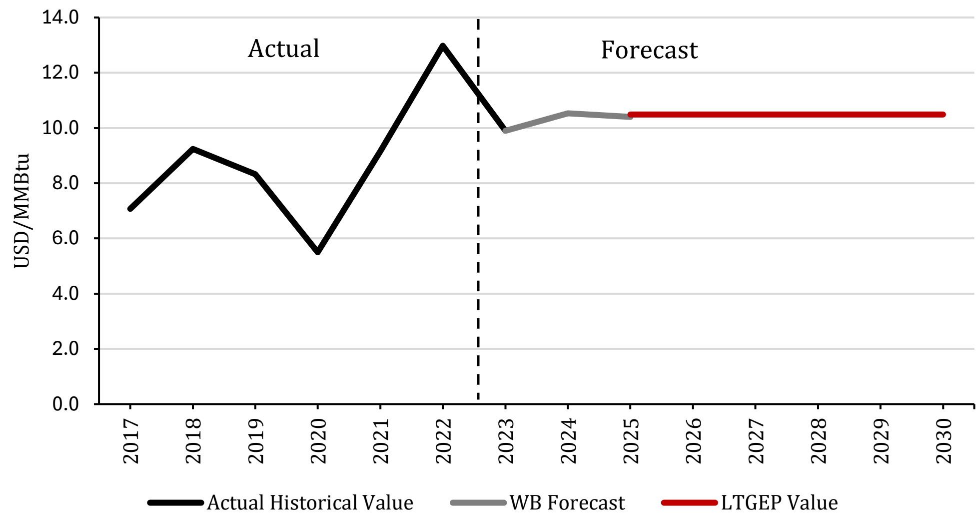


Figure 4.3 - Natural Gas Price Estimation for Analysis in LTGEP

4.3.3.2 Local Natural Gas

The exploration of oil and gas in the Mannar Basin, off North-West coast was commenced in year 2007. Exploration activities initiated with the awarding of one exploration block with an extent of 3,000 sqkm in Mannar Basin. Two wells namely 'Dorado and 'Barracuda' have been drilled, 'Dorado' indicates the availability of natural gas and it is estimated to have approximately 350 bcf of recoverable gas reserves at gas production rate of 70 MMSCFD. The volumetric estimate of the technically complex "Barracuda" discovery has wide range of uncertainty which require extensive reservoir evaluation and well testing. In preliminary estimate on current data and models the gas potential in the wider Mannar Basin is 9 tcf. The Petroleum Development Authority of Sri Lanka (PDASL) is currently planning on joint studies with international oil companies to explore additional oil and gas prospectively.

The price of local natural gas depends on factors such as commercially exploitable quantity, contractual fiscal terms, government tax policy, off take options, delivery options for locations, socio-economic concerns, exploration risk capital, development and operating & maintenance costs, etc. Most of these factors are market sensitive. Hence, it is difficult to make accurate predictions on the gas price and the estimated values based on volatile assumptions. However, the PDASL estimates the local gas price, excluding taxes, delivered to the Norocholai area to be approximately in the range of 8.5 to 10 USD per MMBtu.

4.3.4 Liquefied Petroleum Gas

LPG based power generation has only emerged recently, mainly as an environmentally friendly alternative to oil based power generation. Countries which have plans to develop natural gas power plants in the future have developed LPG based power plants in the short term, with the longer term plan to convert to natural gas once the gas is available. The historic LPG price variation given in Saudi Aramco LPG prices from 2021 to 2023 is shown in figure 4.4 and it shows that LPG prices are quite volatile. In Sri Lanka, LPG supply is primarily made up for most heating and cooking applications. The fuel quality used for the power generation has to have high propane content in contrast to the LPG used for residential applications. In order to use LPG fuel as a power generation option in the country, the necessary local infrastructure needs to be developed before the fuel is to be considered as a power generation option.

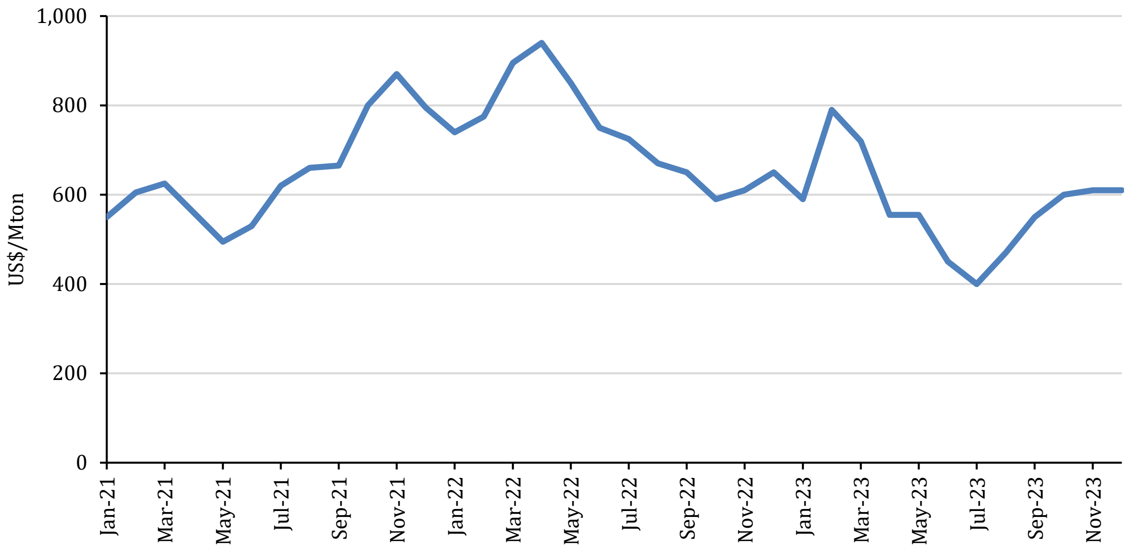


Figure 4.4 - LPG Fuel Price Variation

Source: Saudi Aramco LPG prices

4.3.5 Hydrogen

Hydrogen has recently emerged in the global market as a clean fuel that is capable of operating thermal power plants. Many thermal power plant manufacturers have designed their future plants to operate by blending natural gas with synthetic fuels such as hydrogen. Hydrogen is produced by electrolysis or by splitting natural gas through steam methane reforming (SMR). SMR requires carbon capture and storage (CCS) technologies to be in place, as CO_2 is produced during the process. The levelized cost of Hydrogen production cost from unabated fossil-based sources ranges from 1.0-3.0 USD/kg. Use of CCS technologies to reduce the CO_2 emissions from hydrogen production increases this cost of production up to 1.5 – 3.6 USD/kg. At present, utilizing renewable electricity to produce hydrogen through electrolysis costs around 3.4-12 USD/kg and it is proven as the cleanest method of producing hydrogen [14]. Various other hydrogen production technologies have emerged compromising the cost of production with CO_2 emission during production. However, the production cost of Hydrogen is expected to decrease with the global trends on clean energy and associated decarbonization goals.

In the aim of achieving carbon neutrality by 2050 and other NDC targets, PDASL has developed a comprehensive report on Sri Lanka's National Hydrogen Roadmap which outlines the national hydrogen implementation strategy of the country. Conforming with the national hydrogen roadmap, in LTGEP 2025-2044, hydrogen is introduced as a fuel option for future thermal plants which will be connected to the system beyond 2035. Since 100% hydrogen fired power plants are not commercially viable in the present context, LTGEP 2025-2044 considers only 25% to 30% hydrogen blend by volume which can be readily handled today.

4.3.6 Nuclear

Nuclear power has been considered to be explored as an alternative thermal generation option to avoid excessive dependency on imported fossil fuels for power sector in Sri Lanka. A cabinet approval has been received on 8th September 2010 to consider nuclear as an option to meet the future energy demand and also to consider nuclear power in the generation planning exercise and to carry out a pre-feasibility study on the nuclear option.

Accordingly, Sri Lankan government requested and subsequently received International Atomic Energy agency (IAEA) assistance through the technical cooperation programs.

Under the purview of Ministry of Power; Ceylon Electricity Board (CEB), Sri Lanka Atomic Energy Board (SLAEB) and Sri Lanka Atomic Energy Regulatory Council (SLAERC) contributed as the leading institutions for the project "Establishing a Roadmap for the Nuclear Power Programme in Sri Lanka" with the objective of providing a strong technological, financial, environmental and social understanding for policy makers to take firm decision on the Nuclear Power Development in Sri Lanka.

During the project period, a Steering Committee, Program Management Unit and Working Groups have been formed and several IAEA expert missions have been conducted with the participation of stakeholder organizations.

A draft Comprehensive Report on Nuclear Power Study and Planning Programme of Sri Lanka was prepared in 2020 and the same has been reviewed by International Atomic Energy Agency (IAEA) leading to the final report dated March 2021. This comprehensive report was developed with the objective of providing a strong technological, financial, environmental and social understanding for policy makers to take firm decision on the Nuclear Power Development in Sri Lanka.

International Atomic Energy Agency (IAEA) highlights the importance of considering aspects such as overall Grid Studies, Grid reliability and performance, Unit Size, NPP Operating characteristics, Site Assessment and grid connection, Power system standards, Grid control and communication, Interface between nuclear power plant and the system operator when evaluating the nuclear power option. Accordingly, the electric grid infrastructure was also assessed under the above study. Following are the key points related to grid interconnection based on the above study.

a) Nuclear power is widely regarded as a generation option which requires special consideration when introduced and operated in a power system. Unlike other conventional thermal generation alternatives, Nuclear power facility and the electric grid have a tight inter-dependency that is very important for the safe and economic operation of the nuclear power plant. The electric grid expects the nuclear power facility to provide reliable power similar to any other large thermal power plant but unlike other power plants the nuclear unit requires the grid to support the nuclear facility in normal operation and during start-up, shut down and outage periods for safe operation. In addition to that it is important that the electric grid to provide voltage, frequency and supply continuity at safer and standard level for safe and economic operation of the nuclear facility

b) The upfront investment cost of nuclear power is very high compared to other alternatives even without considering additional investments required for necessary transmission network reinforcements. Therefore, the nuclear power can possibly come in to the mix when the development of other cheaper thermal sources are restricted or strictly decided based on policy to enhance energy security through fuel diversification or to meet long term carbon emission reduction targets.

c) The relatively large unit size of NPP continues to be the biggest technical challenge for the Sri Lankan system. For an isolated grid, the maximum unit size of a nuclear power unit with current grid characteristics is calculated to be in the range of 440 MW - 490 MW by 2044 and calculation based on an industry thumb rule, the possible size of a nuclear power unit turns out to be in the range of 300 MW - 400 MW for the year 2044. This indicates the limited capability of the Sri Lankan power system to integrate a large nuclear power unit as an isolated system.

d) However, the development of cross-border interconnection and pumped storage hydro units could change the system characteristics drastically allowing large units to be connected to the system. The HVDC interconnection and PSPP can well be a prerequisite to integrate a large nuclear power unit to the system in future provided that the terms of operation of the interconnection are set in favour of the NPP operation. Accordingly, during the off-peak duration which becomes critical for the nuclear power operation, possibility of either exporting or storage should be possible to avoid de-loading of the nuclear power plant while maintaining the grid stability at the same time. Alternatively, the potential of small-scale modular reactor nuclear power plants (SMRs) should also be evaluated, considering their commercial viability at the time.

e) Evaluation of the performance of the grid at present reveals that the improvements are required in frequency and voltage performance to match the industry criteria/guidelines for integrating a nuclear power unit to the Grid, safely and reliably.

f) The recent policies of the electricity sector tend to focus more in the direction of enhancing the contribution of variable renewable energy resources which will lead to more decentralized power system. Given the system wide implications caused by variable renewable energy (VRE) technologies such as wind and solar, it is important to recognize the challenges it creates in terms of system stability, security and operation flexibility for the safe and economic operation of a nuclear power unit. Therefore, the future design of the power system is a major factor which will determine the country's ability to accommodate a nuclear power unit in safe and economic manner. It is important to establish and prioritize the long term energy strategy of the country and then to design and develop the power system for the future needs. Such considerations are necessary if the country is to decide on pursuing a nuclear power development program.

Based on the aforementioned findings, it is clear that integrating a conventional nuclear plant to the system is a severe challenge. However, if the above issues are adequately addressed, nuclear power could become a viable option for achieving carbon neutrality by 2050.

Recently the cabinet of ministers have granted approval in principle to proceed with exploring the option of electricity generation using nuclear. Accordingly, the Atomic Energy Board act will be amended. Furthermore, under the patronage of Hon. The Justice Minister appointed a Local Committee comprising Legal and Technical Experts to draft the Comprehensive National Nuclear law in Sri Lankan context

The capacity of proven and widely adopted nuclear power plant designs are in the range of 600 MW to 1,650 MW. Accommodating a nuclear power unit above 600 MW to the Sri Lankan network will be technically challenging with the network condition which depends on the anticipated demand growth and the generation mix which is expected to be dominated by variable renewable energy sources. This technical limitation should be further analysed with scenarios containing the development of cross-border interconnection with India and the planned energy storage additions including pumped storage hydro and battery storage.

Alternative small scale nuclear power plants such as Small Modular Reactors (SMR) are globally still under research level and those can become a proven technology in future.

4.4 Thermal Plant Specific Cost Comparison

The specific costs of the selected candidate plants for different plant factors are tabulated in the Table 4.5. These specific costs are derived by the calculation methodology described in section 7.5 which considers the capital investments cost, operation and maintenance cost, fuel cost and economic life time of a given generation alternative. The specific cost curves reveal how different technologies perform at different plant factors. Power plants which are cost effective at low plant factors are operated as peak load power plants whereas power plants which have lower specific cost at higher plant factors are operated as base load power plants. However, in actual simulations, the size of the generation units is taken into account and it would make a significant effect in the final plant selection. The specific cost curves for the candidate thermal power plants are given in Annex 4.1. Full load heat rates are considered in deriving the specific costs.

4.5 Potential Locations for Power Plant Development

4.5.1 Natural Gas Power Plants

Land area in Muthurajawela has been identified for the development of natural gas based power generation in the Western region. Environment Approval for land reclamation has been obtained by the Sri Lanka Land Development Corporation (SLLDC) to develop natural gas power plants in Muthurajawela area.

4.5.2 Nuclear Power Plants

An International Atomic Energy Agency team of experts has conducted a safety review of Sri Lanka’s selection process to identify potential sites to establish a nuclear plant. The site and External Events Design Review Service (SEED) mission was carried out by IAEA on the request of the Government of Sri Lanka. Six candidate sites from three different regions have been identified during the survey and after further screening, it was decided Pullmoddai, Mullativu site-near Phara ship and Kal-Aru site near Mannar are the most suitable sites for nuclear power plant development in Sri Lanka.

Table 4.5 - Specific Cost of Candidate Thermal Plants in USCts/kWh (LKR/kWh)

Power Plant	Plant Factor								
	0.10	**0.20**	**0.30**	**0.40**	**0.50**	**0.60**	**0.70**	**0.80**	**0.90**
50 MW NG IC Engine	26.45	17.95	15.12	13.70	12.85	12.29	11.88	11.58	11.34
	(86.41)	(58.65)	(49.40)	(44.77	(42.00)	(40.15)	(38.83)	(37.84)	(37.06)
50 MW FO IC Engine	35.97	26.21	22.95	21.33	20.35	19.70	19.23	18.89	18.61
	(117.53)	(85.63)	(75.00)	(69.68	(66.49)	(64.37)	(62.85)	(61.71)	(60.82)
50 MW Dual fuel IC Engine	29.67	19.74	16.43	14.78	13.78	13.12	12.65	12.29	12.02
	(96.94)	(64.50)	(53.68)	(48.28	(45.03)	(42.87)	(41.33)	(40.17)	(39.27)
100 MW NG IC Engine	25.60	17.53	14.84	13.49	12.68	12.15	11.76	11.47	11.25
	(83.65)	(57.27)	(48.48)	(44.08	(41.45)	(39.69)	(38.43)	(37.49)	(36.76)
100 MW FO IC Engine	35.14	25.79	22.68	21.12	20.18	19.56	19.12	18.78	18.52
	(114.81)	(84.27)	(74.09)	(69.00	(65.95)	(63.91)	(62.46)	(61.37)	(60.52)
100 MW Dual fuel Engine	28.84	19.32	16.15	14.57	13.62	12.98	12.53	12.19	11.93
	(94.23)	(63.14)	(52.78)	(47.60	(44.49)	(42.42)	(40.94)	(39.83)	(38.96)
200 MW NG IC Engine	24.77	17.11	14.56	13.28	12.52	12.01	11.64	11.37	11.16
	(80.93)	(55.91)	(47.57)	(43.40)	(40.90)	(39.24)	(38.04)	(37.15)	(36.46)
200 MW FO IC Engine	34.31	25.38	22.40	20.91	20.02	19.42	19.00	18.68	18.43
	(112.09)	(82.91)	(73.19)	(68.32)	(65.41)	(63.46)	(62.07)	(61.03)	(60.22)
200 MW Dual fuel IC Engine	28.01	18.91	15.88	(14.36	13.46	12.85	12.42	12.09	11.84
	(91.53)	(61.80)	(51.89)	(46.94)	(43.96)	(41.98)	(40.57)	(39.50)	(38.68)
50 MW NG Gas Turbine	23.86	18.67	16.94	16.07	15.55	15.20	14.96	14.77	14.63
	(77.95)	(60.99)	(55.33)	(52.51)	(50.81)	(49.68)	(48.87)	(48.27)	(47.79)
50 MW NG Gas Turbine (Aero)	24.46	17.77	15.54	14.43	13.76	13.31	12.99	12.75	12.57
	(79.94)	(58.07)	(50.78)	(47.14)	(44.95)	(43.49)	(42.45)	(41.67)	(41.06)
100 MW NG Gas Turbine	19.73	15.77	14.45	13.79	13.40	13.13	12.94	12.80	12.69
	(64.47)	(51.53)	(47.22)	(45.07)	(43.77)	(42.91)	(42.30)	(41.83)	(41.47)
100 MW NG Gas Turbine (Aero)	21.78	16.51	14.75	13.87	13.34	12.99	12.74	12.55	12.40
	(71.18)	(53.93)	(48.19)	(45.31)	(43.59)	(42.44)	(41.62)	(41.00)	(40.52)
200 MW NG Gas Turbine	18.55	15.23	14.12	13.56	13.23	13.01	12.85	12.73	12.64
	(60.60)	(49.75)	(46.13)	(44.32)	(43.24)	(42.51)	(42.00)	(41.61)	(41.31)
300 MW NG Gas Turbine	16.77	13.92	12.97	12.49	12.21	12.02	11.88	11.78	11.70
	(54.80)	(45.48)	(42.38)	(40.82)	(39.89)	(39.27)	(38.83)	(38.49)	(38.24)
200 MW NG Combined Cycle	27.87	17.98	14.68	13.03	12.04	11.38	10.91	10.55	10.28
	(91.08)	(58.74)	(47.96)	(42.56)	(39.33)	(37.17)	(35.63)	(34.48)	(33.58)
300 MW NG Combined Cycle	26.56	17.31	14.23	12.69	11.76	11.14	10.70	10.37	10.12
	(86.79)	(56.56)	(46.49)	(41.45)	(38.43)	(36.41)	(34.97)	(33.89)	(33.05)
400 MW NG Combined Cycle	24.90	16.10	13.17	11.70	10.82	10.24	9.82	9.50	9.26
	(81.35)	(52.61)	(43.03)	(38.24)	(35.36)	(33.44)	(32.08)	(31.05)	(30.25)
500 MW NG Combined Cycle	24.16	15.68	12.85	11.44	10.59	10.03	9.62	9.32	9.08
	(78.95)	(51.23)	(41.99)	(37.38)	(34.60)	(32.76)	(31.44)	(30.45)	(29.68)
300 MW High Efficient Coal Plant	34.37	19.80	14.94	12.51	11.06	10.09	9.39	8.87	8.47
	(112.29)	(64.69)	(48.82)	(40.89)	(36.13)	(32.96)	(30.69)	(28.99)	(27.67)
600 MW Super Critical Coal Plant	35.85	20.37	15.21	12.63	11.09	10.05	9.32	8.76	8.33
	(117.13)	(66.56)	(49.71)	(41.28)	(36.22)	(32.85)	(30.44)	(28.63)	(27.23)
600 MW Nuclear Power Plant	74.55	37.67	25.38	19.23	15.54	13.08	11.33	10.01	8.99
	(243.59)	(123.09)	(82.92)	(62.83)	(50.78)	(42.75)	(37.01)	(32.71)	(29.37)

CHAPTER 5
RENEWABLE GENERATION AND STORAGE OPTIONS

5.1 Background

Sri Lanka being a tropical country is blessed with indigenous renewable energy resources and these indigenous resources have underpinned the economic growth for decades. Country's electricity needs were predominantly met by renewable energy sources, with prime contribution from the major hydro power resources. That has enabled the country to maintain green credential with per capita low carbon emissions level in electricity generation throughout the history. The rising economic growth and the energy demand led the expansion of other renewable energy sector as well as thermal based resources. Though the large hydro resources played a major role in renewable energy share in the past, variable forms renewable resources such as wind and solar are becoming dominant contributors in the future. In line with the global efforts to mitigate climate change implications, Sri Lanka has progressively enhanced its ambitious targets and development activities on renewable energy development. Accordingly, a substantial growth in the indigenous wind and solar resource development is envisaged as the country is moving forward on a low carbon pathway in meeting its future electricity requirement.

Renewable energy sources encompass a broad range of continuously replenishing natural energy resources and technologies. A renewable energy system converts the energy in sunlight, wind, stored water, sea-waves, geothermal heat or biomass into heat or electricity without exhausting the source. Sri Lanka has harnessed major renewable resources (large hydro) to almost its maximum economical potential. Developing and harnessing the energy from renewable energy sources such as mini hydro, wind, solar, biomass and municipal waste are progressing at present.

Hydro power and biomass power generation are not intermittent whereas wind and solar photovoltaic sources are highly intermittent and seasonal in nature. These inherent physical characteristics of the resources cause challenges in grid integration and different power systems have different capability for grid integration based on system characteristics as well as resource characteristics.

5.2 Major Hydro Development

Sri Lanka was a Hydro Power dependent nation till the late 1990s in which majority of the power requirement was met from hydro power plants. The hydro power potential in the country has been vastly exploited and only a limited amount of generation projects remains in the pipeline. Several prospective candidate hydro projects have been identified in the Master Plan Study [15], 1989. These include 27 sites having a total capacity of approximately 870 MW. A large part of this hydro potential in Sri Lanka has been already exploited and the Uma Oya Hydro Power Project is the latest addition to large scale hydro power projects in Sri Lanka.

5.2.1 Committed Hydro Power Projects

Moragolla hydro power project is the last hydro power project identified in the Master Plan Study. The Moragolla Hydropower Project located downstream of the Kotmale power station and approximately 3.5 km downstream from the confluence of the Mahaweli Ganga with the Kotmale Oya. Total storage capacity of the reservoir is 4.66 MCM and the annual mean energy expected is 97.6 GWh. The Moragolla Hydropower Project was first identified in "Report on a Survey of Resources of the Mahaweli Ganga Basin, Ceylon, Hunting Survey Corporation, 1962." prepared in cooperation with the Survey General of Ceylon. The location was highlighted as one of potential hydropower sites in "Master Plan for the Electricity Supply of Sri Lanka, German Agency of Technical Cooperation, 1988".

The 31 MW Moragolla Hydropower Project is designed as a run-of-river scheme, and it will operate as peaking power plant to operate from 5-9 pm and at other times if there is sufficient water (mainly in the monsoon season). The Power plant is currently under construction utilizing funds from Asian Development Bank. The power plant is expected to be operational by the latter part of 2024.

5.2.2 Candidate Hydro Power Project

Multipurpose hydro projects such as Thalpitigala and Gin Gaga are identified to be developed by the Ministry of Irrigation and Water Resource Management.

The preliminary feasibility studies and EIA studies of the Thalpitigala Hydro Power Project in Uma Oya basin have been finalized. As per the feasibility studies, the power plant is 15MW (2 x 7.5MW) with an estimated annual energy contribution of 52.4 GWh (at 39% plant factor). Storage capacity of the reservoir is 17.96 MCM. However, due to difficulties in securing project finances, the project is on hold at present.

The preliminary feasibility studies for Gin Ganga hydro project are in progress and the parameters of the hydro power plant are yet to be finalized.

5.2.3 Capability of Hydro Power Plants

Sri Lankan power system has a fairly large portion of installed hydropower capacity. As hydro generation makes a considerable impact on the dispatch of high cost thermal power, it is necessary to assess the energy generating potential of the hydropower system to a high degree of accuracy. However, this assessment is difficult owing to the multipurpose nature of some reservoirs, which have to satisfy the downstream irrigation requirements as well. Further, the climatic conditions of Sri Lanka are characterized by the monsoons, causing inflows to the reservoirs as well as the irrigation demands to fluctuate over the year exhibiting a strong seasonal pattern. Furthermore, El Nino and La Nina climatic effects are occasionally seen which drastically effect

The annual energy variation of the hydro system was evaluated using the Stochastic Dual Dynamic Programming (SDDP) model. As inputs for the model, inflow data for past 40 years and the operational details of hydro plants are entered and the model allows a more detailed representation of the uncertainty of future inflows through the use of multiple scenarios in the time-coupled optimization.

Based on SDDP simulation outputs, hydro generation figures for the existing and new hydro plants are obtained and average annual hydro generation figures for scenarios is shown in Figure 5.1. This shows that the capability of all major hydro power plants after commissioning of new hydro power plants could vary from around 4,000 GWh to 6,500 GWh.

Long term planning exercise has been carried out using 10 scenarios while for short term operational studies up to 100 hydro scenarios have been simulated. Monthly pattern of hydro inflows and subsequent dispatch of hydro generation is depicted in Figure 5.2.

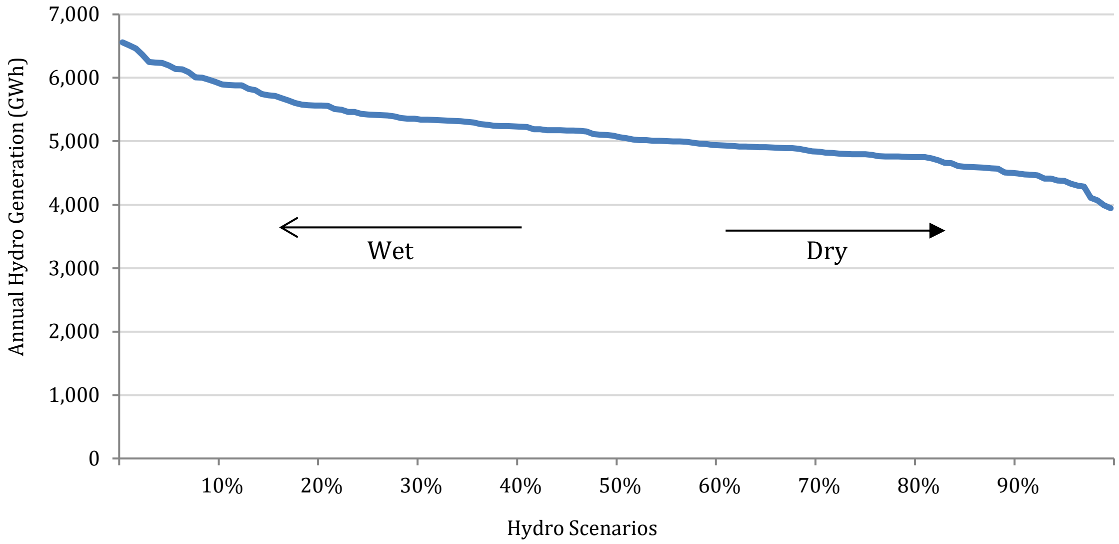


Figure 5.1 -Potential Annual Energy from Major Hydro based on Past Hydrological Data

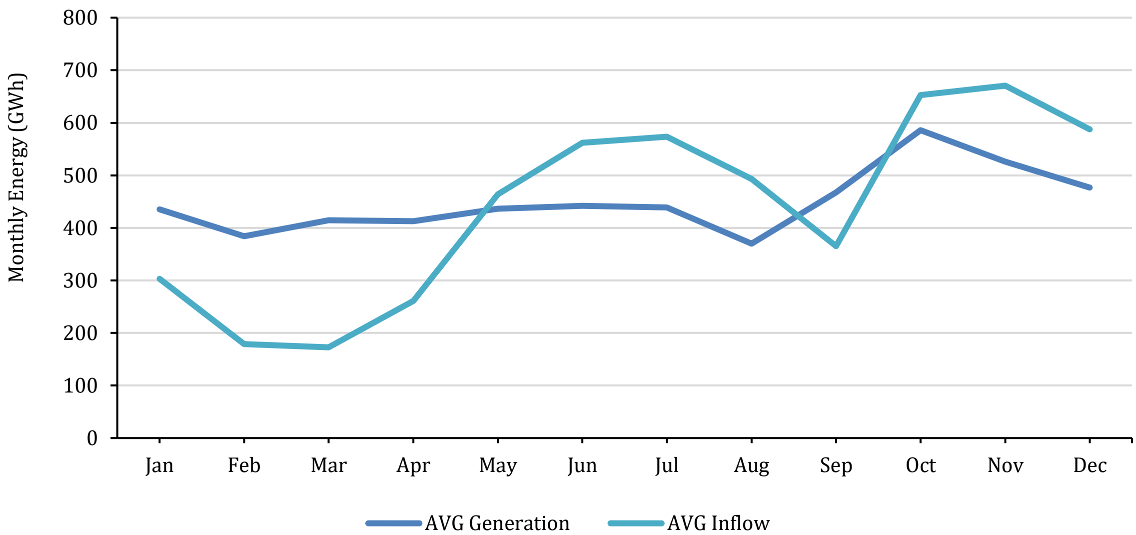


Figure 5.2 - Potential Monthly Energy from Major Hydro in Average Hydro Condition

5.3 Hydro Power Capacity Extensions

The capability of providing peak power support from hydro power was studied under the JICA funded "Hydro Power Optimization Study of 2004". Given below is a brief summary of expansions of existing hydro stations studied under the "Hydro Power Optimization Study" [16].

5.3.1 Mahaweli Complex

The "Hydro Power Optimization Study of 2004" suggested possible expansions of Ukuwela, Victoria and Rantambe Power Stations due to high plant factors. Out of those it is difficult to expand

Rantambe for peaking requirements because it has to comply with water release for irrigation demand as a priority.

(a) Victoria Power Station

(i) Victoria Expansion:

CEB has identified expansion of Victoria Hydro Power Plant as an option to meet the peak power demand. A feasibility study for expansion of Victoria Hydro Power station has been done in 2009 [17] and had considered three options for the expansion. Those were; addition of another power house nearby the existing power plant (base option), addition of a surface type power house 2km downstream of the existing power house (downstream option) and using of Victoria and Randenigala reservoirs as a pumped storage power plant (pumped storage option). From the feasibility study, it was concluded that the addition of the new power house closer to the existing power plant is an economically viable option as provisions have already been made for the expansion when the existing power plant was constructed. Under this expansion, two units of 114 MW each will be added. This expansion could double the capacity of Victoria while the energy benefits are as follows.

Table 5.1 – Details of Victoria Expansion

	Annual Energy (GWh)	Peak Energy (GWh)	Off-Peak Energy (GWh)	95% Dependable Capacity
Spilled Discharge Deducted				
Existing Only	634	230	404	209
Existing+ Expansion	635	467	168	379
Spilled Discharge not Deducted				
Existing Only	689	230	459	209
Existing+ Expansion	716	469	247	385

Source: Feasibility Study for Expansion of Victoria Hydropower Station, June 2009

This expansion scheme has an advantage of not lowering the reservoir water level during construction period since the intake facilities for the expansion project were already constructed during the initial construction phase of the existing power plant. As of October 2008, this project requires approximately USD 222 million for implementation. Further analysis of the project is required before incorporating into the Long Term Generation Expansion Plan.

(ii) Victoria Upgradation:

An alternate proposal has been proposed by the Generation Division of CEB to upgrade the existing capacity of Generation units installed in Victoria. The proposal elaborates on rehabilitation works on the turbine and generator while upgrading the capacity of a single unit from 70MW to 92.8 MW by increasing the turbine discharge to 52.8m3/s. The total output from the Victoria Power Station is expected to be 273 MW. It shall enable usage of excess water in high inflow seasons and also enhance the operating flexibility of the Victoria power station for system frequency controlling requirements.

According to the ongoing study by 'Mahaweli Water Security Investment Program' under the Ministry of Mahaweli Development and Environment, it has been proposed to transfer water from the Randenigala reservoir to Kaluganga reservoir to meet the water demand requirements of North Central Province. This will impact the water availability and operation of the reservoirs of the Mahaweli complex. Therefore, the feasibility of Victoria expansion and upgradation should be further reviewed based on the study outcome of Mahaweli Water Security Investment Program before incorporating into the Long Term Generation Expansion Plan.

(b) Upper Kotmale Diversion:

Diversion of Pundalu Oya and Pundalu Falls tributary is proposed under this project. The Upper Kothmale diversion project will increase the annual energy generation of Upper Kothmale Hydro Power Plant by 39 GWh. For the implementation of above project, Operation of Upper Kothmale Hydro Power Plant needs to be interrupted for 6 months resulting reduction of 150 MW capacity and 200 GWh on average over the six month period.

(c) Kotmale Project:

Provision for capacity expansion has been kept in the existing Kotmale Power Station. At present 3 x 67MW generators are installed in the Kotmale Power Station with an annual average energy output of 455 GWh. The amount of energy could be increased by about 20% by raising the dam crest from elevation 706.5m to 735.0 masl.

5.3.2 Samanala Complex

Samanalawewa hydropower scheme has envisaged the development of the potential in two stages during initial studies. The existing Samanalawewa power station which was developed under stage I has two generators rated at 60 MW each. Stage II of the scheme envisaged the development of Diyawini Oya reservoir and further two units of 60 MW each aimed at providing the needs of additional peaking capacity in future. During construction stage of Samanalawewa, provisions such as a bifurcation with bulk head gate in the penstock and a space for an addition of two 60MW units have been made to extend the capacity of the power plant to 240 MW.

Stage II of the project was reviewed by CECB in 2000. "Samanalawewa Hydropower Project - Feasibility of the development of stage II" report by CECB concludes that the development of Diyawini Oya is not economical and recommends installation of one additional 60MW capacity with provisions to add the next unit of similar capacity in future.

The stage II development was again reviewed during "The Study of Hydropower Optimization in Sri Lanka" in February 2004. Referring the previous study, the development of Diyawini reservoir is excluded from the analysis but considered the addition of 1 unit as well as 2 units for evaluation. A summary of expansion details according to this report is shown in Table 5.2. Overall evaluation in this study suggested that further investigations and studies are required.

Table 5.2 – Expansion Details of Samanalawewa Power Station

	Unit	Existing	Existing + 1 Unit Expansion	Existing + 2 Units Expansion
Plant Capacity	MW	120	180	240
Peak Duration	Hrs	6	4	3
95% Dependable Capacity	MW	120	172	225
Primary Energy	GWh	262	259	254
Secondary Energy	GWh	89	55	0
Total Energy	GWh	351	314	254

Source: The Study of Hydropower Optimization in Sri Lanka, Feb 2004

5.3.3 Laxapana Complex

During the Phase E of the Master Plan for the Electricity Supply in Sri Lanka, 1990 [18], some upgrading measures at Laxapana Complex have been studied. Also, under the Hydro Power Optimization Study further studies were carried out to upgrade Wimalasurendra Power Station, New Laxapana power station & Old Laxapana Power Station. And also, for upgrading of the Polpitiya Power Stations, studies have been carried out. Under the upgrading of Wimalasurendra and New Laxapana Power Stations, planned replacement of generator, turbine governor excitation & controls and transformer protection have been completed by the Generation Division. Due to the enhancement the maximum capacity of the New Laxapana Power Station can be increased from 100 MW to 116 MW. Planned replacement of generator, turbine governor excitation & controls of the Old Laxapana Station were completed increasing the plant capacity (from 50 MW to 53.8 MW) and efficiency.

Expansion of Polpitiya Power Station has been implemented and the plant capacity has been increased to 90 MW from 75 MW from 2019 onwards.

5.4 Other Renewable Energy Development

As the large hydro resource of the country have been largely developed over the past decades, the other renewable energy sources, mainly small hydro, wind, biomass and solar resources remain as the main potential indigenous resources for future development. The tropical climate of the country influenced by monsoon winds characterizes these resources and distinct seasonality exists in hydro and wind resources.

The grid connected small renewable energy resource development was first initiated in 1997 through the regularization of small renewable energy power producers by Ceylon Electricity Board with the publication of standardized power purchase agreement (SPPA). The growth of other renewable energy sources in Sri Lanka in commercial scale commenced with the development of mini-hydro resources in 1997 and it continued under feed-in tariff system. The introduction of cost reflective, technology specific feed-in tariff in 2007 paved the way for the development of wind resources and considerable growth was achieved in local wind resource development. With the introduction of roof top solar Net Metering facility in the country in 2009 followed by the rapid technology cost decline and rapid growth in the global solar PV industry after 2010, solar resource development gained steep growth over the past years. Subsequent introduction of Net Metering, Net Accounting and Net Plus schemes stimulated the growth of domestic and industrial customers' rooftop solar schemes. Grid scale solar developments also started growing at different scales. The other renewable energy project development was led largely by the private sector with the facilitation of Ceylon Electricity Board and the Sri Lanka Sustainable Energy Authority and the first large scale renewable energy project of the country, the 100 MW wind farm in Mannar island was developed by the Ceylon Electricity Board. The renewable energy projects have been successful in attracting investment and the renewable energy industry has been growing continuously over the years. The figure 5.3 below illustrates the growth of other renewable energy capacity over the last two decades.

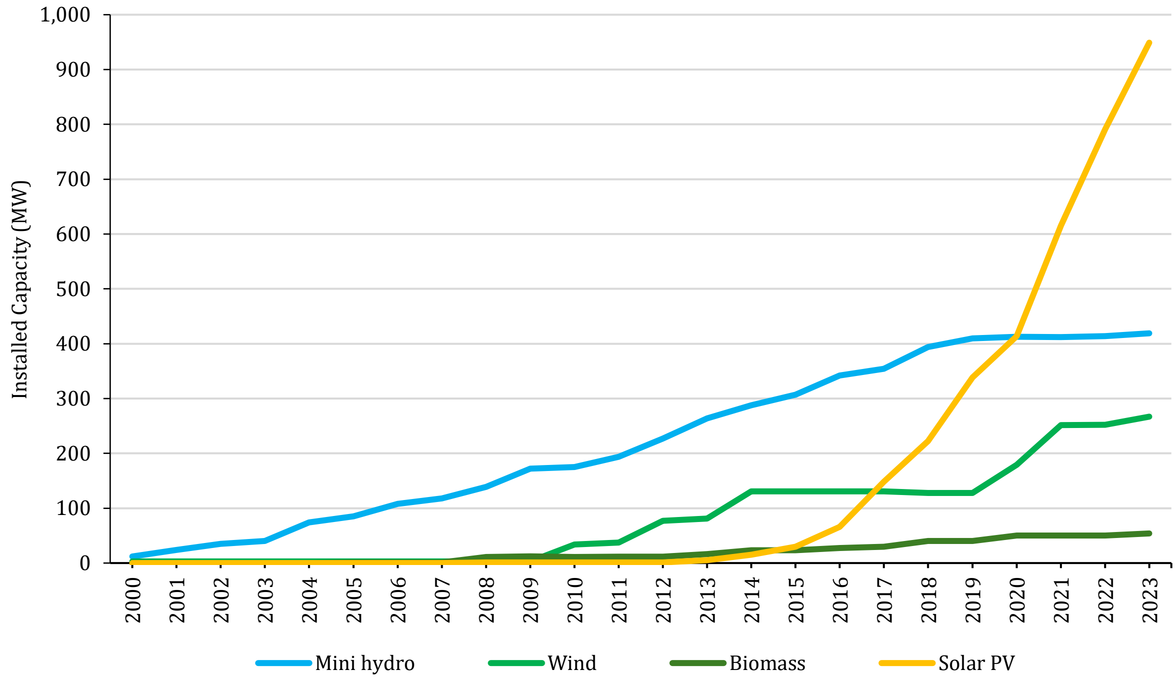


Figure 5.3 - Other Renewable Installed Capacity by source (2000-2023)

Share of Other Renewable Energy based generation at present is 21.5% of total energy generation in the country and its contribution is expected to increase in the future. At the end of 2023, 1693 MW of other renewable energy power plants have been connected to the national grid and the total comprises 419 MW of mini-hydro, 267 MW of wind, 138 MW of solar (without roof top solar) and 54 MW of biomass based generation capacities. in addition, the rooftop solar embedded at the consumer end has a capacity approximately 815 MW by the end of 2023, and is growing rapidly.

Other renewable energy sources have been under the cost reflective technology specific tariff scheme since 2012 and with the falling technology costs and rising competition in the industry, competitive bidding process is increasingly being followed at present for the development of renewable energy projects. Table 5.3 shows the growth of the renewable energy capacity and energy contribution (at end of each year) compared to the overall capacity and generation for past 15 years in the country.

Table 5.3 – Energy and Capacity Contribution from Other Renewable Sources

Year	ORE Generation[1] (GWh)	ORE Generation from Total Generation	ORE Capacity (MW)	ORE Capacity from Total Capacity
2004	208	3%	73	3%
2005	282	3%	88	4%
2006	349	4%	112	5%
2007	347	4%	119	5%
2008	438	4%	161	6%
2009	552	6%	181	7%
2010	731	7%	220	8%
2011	725	6%	244	8%
2012	736	6%	317	10%
2013	1,179	10%	367	11%
2014	1,217	10%	458	12%
2015	1,467	11%	491	13%
2016	1,167	8%	566	14%
2017	1,479	10%	663	16%
2018	1,742	11%	784	19%
2019	1,806	11%	917	20%
2020	1,932	12%	1,055	23%
2021	3,005	18%	1,330	28%
2022	3,050	19%	1,507	31%
2023	3,375	21%	1,689	33%

[1]Solar rooftop export from CEB & LECO consumers are considered from 2019 onwards and self-consumption of such plants are excluded.

5.5 Mini Hydro Resource Development

History of small hydro power generation in Sri Lanka spans over a century and it is mainly associated with the power generation for the large scale tea plantations in the colonial era. Since then, the small hydro capacity grew gradually until 1960s when the electricity grid was extended to provide supply of electricity. In 1990s, CEB's assistance was provided for the development of the Mini hydropower sector with the required assistance to the private sector. The procedure for electricity purchases from Small Power Producers (SPPs) by the CEB was regularized beginning in 1997 with the publication of a standardized power purchase agreement (SPPA) which included a scheme for calculating the purchase price based on the avoided cost principle. Instead of avoided cost based tariff, a three-tier tariff was introduced with effect from year 2008. Currently the technology specific cost reflective tariff introduced in 2012 is in force with periodic revisions of tariff rates.

The geo-climatic condition in Sri Lanka is favourable for the mini hydro development and several past studies have assessed the potential for the development of mini hydro resources. A comprehensive study has been carried out as part of the Dam Safety and Water Resources Planning project (DSWRP) of the Ministry of Irrigation and Water Resources, focusing on 13 river basins of the country, and the study has concluded that the total mini hydro potential in the country as

873MW. As at the end of 2023, the total grid connected mini hydro capacity is 419 MW which comprises 394 MW developed by the private sector and 25 MW under the Moragahakanda Kaluganga Development multi-purpose development project by the Ministry of Mahaweli Development and Environment with the Mahaweli Authority of Sri Lanka. The Sustainable Energy Authority has identified a potential of approximately 400 MW future capacity additions based on applications received from project proponents. In this long term generation expansion plan, the mini hydro capacity is expected to grow moderately within next twenty years as most of the attractive resources and sites have been already developed. Therefore, future capacity additions are not restricted and shall be considered case by case, depending on the feasibility of implementation. The typical Production profile of mini hydro energy resource is depicted in Figure 5.4. It is observed that the majority of the mini hydro energy productions occurs from the months of September to December.

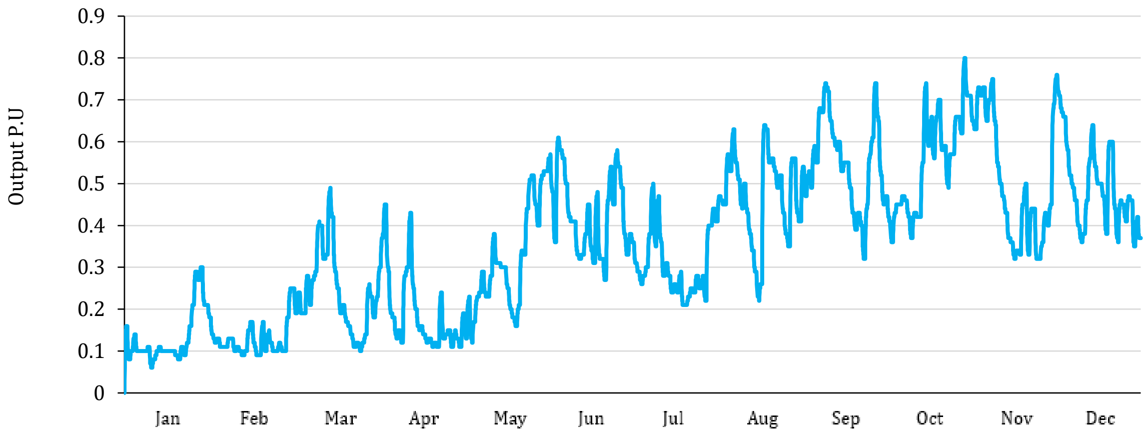


Figure 5.4 - Modelled Production Profile of Mini Hydro Resource

5.6 Wind Resource Development

Wind power development can be broadly classified into two main categories of onshore wind power development and offshore wind power development.

5.6.1 Onshore Wind Power Development

Sri Lanka is blessed with quality wind resources mainly located in the North-western coastal area, Northern area and central highland area. The wind resource patterns are mainly characterized by the Asian monsoon wind system and mainly the richest wind power potential of the island (Class 4 and above) is available in the areas that are exposed to southwest monsoon. Only a portion of the total available potential is economically exploitable due to reasons such as competing land uses, accessibility and environmentally sensitive concerns. Ceylon Electricity Board has identified these exploitable wind resource potentials and prioritized their development activities together with the expansion of transmission infrastructure.

The economically exploitable wind power potential identified in the preliminary resource potential assessment was mainly concentrated on Northern and North Western coastal line of the country. The North Eastern coast and the central hills also hold certain amount of wind resources but not prioritized for the immediate development in large scale due to development constraints. The Mannar area, Northern area and Puttalam area are priority resource area to develop wind power compared to other regions of the country. In recent studies, new resource areas for wind power development in north central region have been identified by the Sustainable Energy Authority. However, only preliminary assessment is available without any resource measurement data at present. Both public and private sector participation in developing these resources is taking place and at present competitive mechanisms are being followed in developing projects. The first pilot scale wind farm of 3 MW was developed at Hambantota by Ceylon Electricity Board in early 1990s and Private sector started developing successful wind power projects during 2010 in Puttalam area. The 100 MW Thambapavani Wind Farm in the Southern coast of the Mannar island is the first large scale wind farm of the country. It was developed by Ceylon Electricity Board in year 2020 with financial assistance from Asian Development Bank (ADB). Sri Lanka Sustainable Energy Authority had identified further wind resource development zones in for large scale wind farm development in Mannar island, Silawathura, Pooneryn, Veravill and Karachchi areas in which land area have been earmarked and gazetted.

5.6.2 Offshore Wind Power Development

The large potential for offshore wind power development in north western and south eastern regions have been identified by initial assessments in World Bank Group studies. However, there is lack of any detailed studies at present and the Sustainable Energy Authority shall engage in further studies to evaluate its potential. The capital cost of offshore wind power development is nearly 3-4 times higher than onshore wind power development; hence detailed studies are essential if development of such resources is to be embarked in future. Offshore wind power is classified into two main categories based on their foundation capability. Fixed bottom offshore wind power is the more matured technology which is deployed at shallow sea conditions. The floating offshore wind technology is presently emerging to develop offshore wind in deep sea conditions.

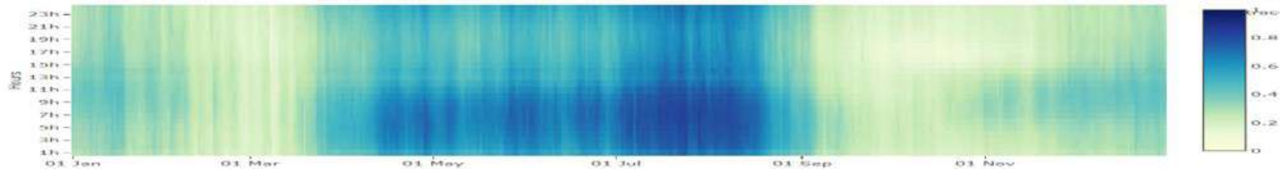
Although in the initial study from World Bank Group 56 GW offshore potential has been identified, it reiterates that the development of the entire 56GW of resource potential will not be practical amount of offshore wind actually constructed will be far lower. Hence it envisages a high growth scenario for development of 4 GW offshore wind by year 2050. The main regions identified for off shore wind power is at North West, North and South East Region of Sri Lanka. The low sea depth in North West and Northern region makes it ideal for development of fixed bottom offshore wind power plants in the region. However, since sea depth is higher in south east region, floating off shore wind technology is considered to be the viable technology for that region.

5.6.3 Wind Resource Assessment

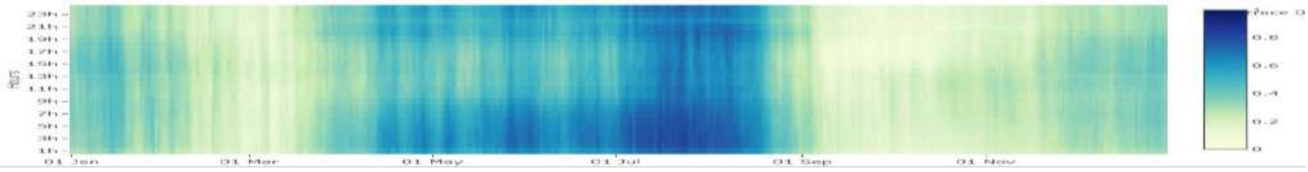
The seasonality characteristics are prominent for all wind regions in the island. It can be observed that in all regions majority of the annual wind energy is produced during the months from May to September, which is categorized as the high wind season. The wind power output variation is low during this season compared with higher variations in the low wind season.

The stochastic outputs based on 40 years satellite data were used in modelling the wind resources of each region, while the same were verified with actual measurement data available of each site. Figure 5.5 illustrates the prominent seasonality characteristics of wind resources in each region.

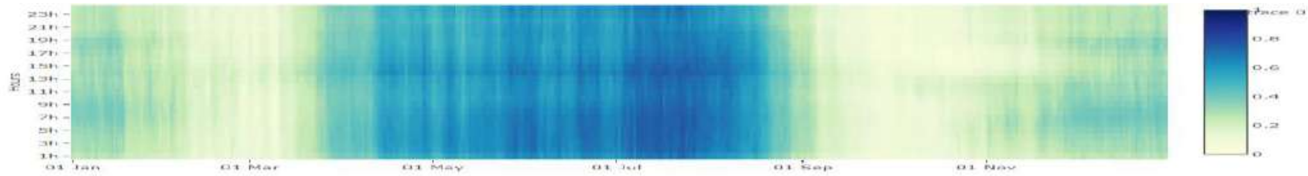
Puttalam Region - (Average Plant Factor 32%)



Northern Region - (Average Plant Factor 34%)



Mannar Region - (Average Plant Factor 40%)



Offshore Region - (Average Plant Factor 50%)

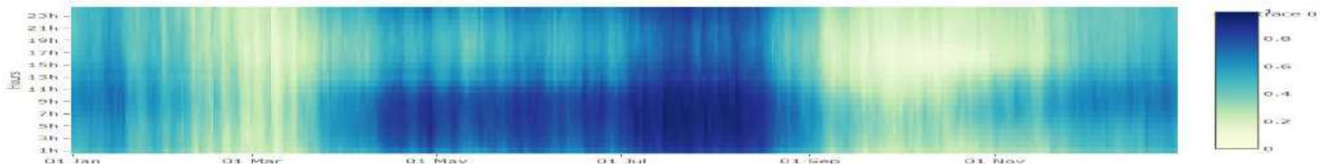


Figure 5.5 - Annual Variation of Wind Power Production in Different Regions

5.7 Solar Resource Development

Sri Lanka, being located within the equatorial belt, has substantial potential in solar resource. Solar resource maps of the country indicate the existence of higher solar resource potentials in the Northern half, Eastern and Southern parts of the country. Resource potential in other areas including mountainous regions is mainly characterized by climatic and geographical features. The cost of solar PV technology is becoming increasingly competitive and a steady and strong growth is expected to continue for both rooftop and ground mounted applications in commercial scale. The local solar power industry gained significant momentum over the past years due to number of support schemes and development initiatives of the Ministry of Power, Ceylon Electricity Board and the Sri Lanka Sustainable Energy Authority.

The technical potential of integrating solar PV resources into the power system is assessed by Ceylon Electricity Board. The production of solar energy is limited to several hours during the day time and has certain seasonal characteristics. It is observed that solar energy production is highest during the dry season from January to April, while significant reduction of energy output is seen during the wet season. Even though largescale variations are seen in individual small scale installations, the effect can be reduced with geographical scattering of solar power plants. Figure 5.6 illustrates the annual variations of solar power, while Figure 5.7 illustrates the effect of geographical scattering of solar resources.

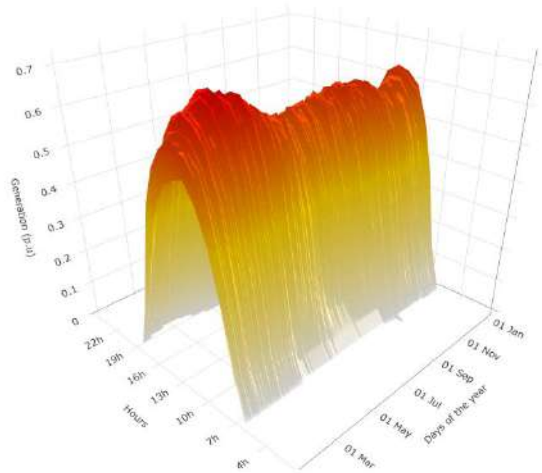


Figure 5.6 - Annul Variation of Solar Energy

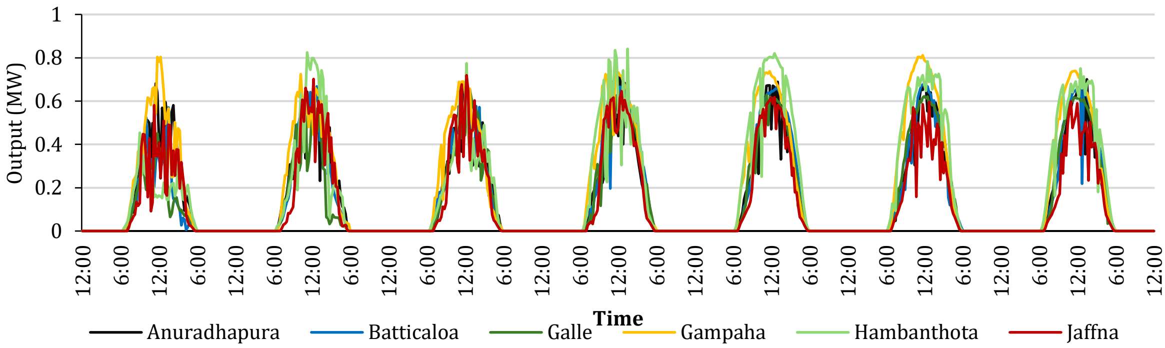


Figure 5.7 - Geographical scattering Effect of Solar Resource

Both large scale and small scale development is planned for the next twenty years as solar PV is the main form of renewable energy source that indicates the highest growth for long term. The solar power development schemes are implemented through following mechanisms.

1. Grid connected large scale solar (10-100 MW)
2. Grid connected small scale solar (1 - 10 MW)
3. Distribution network connected embedded solar (Rooftop)

5.7.1 Grid Connected Large Scale Solar (10-100 MW)

Large scale solar PV park development has its own advantages in economies of scale and also the technical challenges in grid integration. Large scale solar PV parks in the scale of 100 MW are planned for future development in Northern, Southern and Eastern areas. The Sri Lanka Sustainable Energy Authority has identified potential resource locations for large scale development in Northern, North Eastern, Eastern, North Central, North Western and Southern regions to support a longer term large scale development plan. Potential resource locations for the development of medium scale ground mounted PV capacities above 10 MW and below 100 MW have also been identified around the island. Prioritizing the development of large scale resources depending on the resource quality and associated development cost is important for achieving the economic efficiency of the long term renewable energy development program.

The Grid connected ground mounted solar parks have been modelled based on single axis tracking mode configuration which offers higher energy production. However, the land limitation and obtaining necessary approvals for large projects have been highly challenging.

Floating solar technology alternative has the potential to resolve the land limitation issues for developing solar power plants. In this, solar panels are usually mounted upon a floating structure to keep its location fixed. The floating structure is anchored and moored. In addition to resolving land limitation issues floating solar technologies offer higher gains in energy production due to lower PV array temperature and reduce water evaporation of reservoirs. A floating solar power plant with a capacity of 42 kW was installed at the University of Jaffna in 2020 marking the country's first such project as a pilot project. Moreover, the Sri Lanka Sustainable Energy Authority has identified multiple potential reservoir locations to develop large scale floating solar projects and detailed techno-economic assessments for each resource sites are required for long term investment decisions.

The grid connected solar parks are expected to be connected with facilities for ramp control and storage for energy shifting purposes. They shall be dispatchable power plants capable of operating according to the dispatch instructions of the National System Control Centre. Since large amount of conventional generation is expected to be displaced from these renewable sources, they would be required to provide the necessary ancillary services as stipulated through grid codes and regulations.

5.7.2 Grid Connected Small Scale Solar (1 - 10 MW)

One strategy to minimize the inherent variability challenge of solar PV resources is geographical scattering of solar PV installations as there is a greater diversity in variability characteristics in smallest time scales. Studies conducted by Ceylon Electricity Board have identified that the geographical distribution of solar PV projects can reduce the overall variability levels experienced by the system notably.

Even though the solar resource is abundantly available through the island, availability of land for large scale development is limited. However, potential for small scale development is identified in many regions of the country. Furthermore, the grid infrastructure is readily available to absorb small scale projects around the island. Hence is easier to develop than large scale projects.

A cumulative capacity of 51 MW was connected to the grid from the feed in tariff system by year 2017. In line with the second phase of the accelerated solar development program of the government, Ceylon Electricity Board initiated the development of 60 MW with 1 MW solar projects at 20 selected Grid substations through international competitive bidding process under Build, Own & Operate (BOO) basis. Subsequently several phases of the same scheme were launched to develop small scale solar PV plants with improved contractual terms to provide more facilitation and flexibility to developers. A cumulative capacity of over 300 MW scattered around the island have been tendered through competitive bidding during different phases. These projects are presently at various stages of development and is expected to be connected to the grid during 2024-2026 time period.

In addition to this the feed in tariff was reintroduced with attractive tariffs to promote scattered development. Few projects are currently at development stage under this scheme and are expected to be commissioned within the period from 2024-2026.

Two floating solar power generation pilot projects with a capacity of 1 MW each are been implemented on the surfaces of the Chandrika Wewa Reservoir and Kiriibban wewa Reservoir with assistance from the Korean Government. These projects shall pave way for installation of larger capacity projects in future.

5.7.3 Distribution Network Connected Embedded Solar

Distribution network connected Embedded Solar is mainly classified in to two subcategories of rooftop solar and small-scale ground mounted solar.

The roof top solar systems are starting to play a prominent role in providing energy needs of the electricity consumers and it is an effective form of embedded generation located at the end user. Since these solar PV installations utilize the available rooftop spaces, those have less impact to the environment caused by land use. The ‘’Energy Banking Facility’ for such micro-scale generating facilities, commonly known as the ‘Net Energy Metering Facility’ for electricity consumers was first introduced in Sri Lanka in 2010 by the Ministry of Power and Renewable Energy through the power utilities Ceylon Electricity Boards (CEB) and Lanka Electric Company (LECO). Subsequently, the Government of Sri Lanka (GOSL) launched accelerated solar development program in 2016 to promote roof top solar installations in the country. In order to support the GOSL’s renewable energy promotional drive, the Net Metering concept was further enhanced by introducing other schemes at different stages. Following are the schemes introduced to develop rooftop solar installations.

- Net Metering - Consumer is not paid for the export of energy, but is given credit (in kWh) for consumption of same amount of energy for subsequent billing periods
- Net Accounting - Consumer is compensated for the exported energy with a two tier tariff for 20-year period
- Net Plus -Consumer can install a solar PV generation unit and all the generated energy will be exported to the grid. Unlike previous two schemes there is no linkage between the consumption and electricity generation
- Net Plus Plus – Extension of Net Plus scheme to develop Solar PV units above the consumption contract demand.

The total installed capacity of rooftop solar PV under these schemes has reached 815 MW (both CEB and LECO) by the end of 2023.

These schemes change the role of the traditional electricity consumer to a consumer and producer. Rooftop solar capacity is expected to grow further in the forthcoming years. However, it is essential to address the main technical challenges encountered at the distribution level. The voltage issues in some distribution feeders have restricted development of rooftop solar in certain distribution areas. Hence it is important to streamline the roof top solar PV program and to maintain the quality of the electricity supply to the consumers.

5.8 Biomass and Other Resource Development

5.8.1 Biomass Power Development

Biomass is a renewable resource that is primarily based on organic matter as a fuel related to plants, vegetation and waste that generates from agricultural and industrial process as a by-product or residue. Growing biomass as a fuel for Dendro power generation gained attention in the recent past and at the end of 2023 total biomass based capacity was 44 MW including both dendro and agricultural waste based power generation. Evidently, the growth of the biomass capacity in the past has not achieved the expected progress primarily due to the factors associated with biomass fuel supply mechanisms and only a moderate growth is expected in future. However, being a non-intermittent form of generation, the capacity additions are not strictly limited to the planned capacities and further capacity additions shall be considered depending on the feasibility and success of implementation.

5.8.2 Municipal Solid Waste Based Power Generation

Developments of grid scale waste-to-energy projects is identified as sustainable and timely solution for the solid waste management problems in the urban areas. As large amount of solid waste is accumulated throughout the country, converting Municipal Solid Waste to energy has a tremendous potential in waste management, reducing the negative social, health and environmental effects. Different technologies are available for the energy conversion process and the composition and characteristics of accumulated waste as a fuel is an important factor when utilizing for power generation purpose.

Sri Lanka's first Waste-to-Energy Power project was developed and commissioned in Kerawalapitiya area. The 10 MW project is able to convert 700 tons of solid waste, nearly 20% of the household waste to electricity each day. The project was developed with private sector investment with the facilitation of Ceylon Electricity Board and Sustainable Energy Authority.

5.8.3 Other Forms of Renewable Energy Technologies

Other forms of renewable energy include power generation from Geo thermal, Wave, Tidal and concentrated solar power. Although CEB has provided opportunity for the development of other forms of new renewable energy sources by requesting international proposals to develop new renewable technology applications by calling proposals (in 2018), no satisfactory proposals have been received. It is expected that such technologies will get attractive after having reached their commercial capability beyond present research level. However, planning studies do not restrict development of any pilot scale projects from these technologies, but are not considered as candidates for major projects at this stage.

5.9 Renewable Energy Zones

Assessing resource potential for future development is a key step in the study process. Remaining major hydro and mini hydro resource potential were considered in the study. The total exploitable renewable energy potential is based on the resource potentials identified by Sri Lanka Sustainable Energy Authority. It is assessed considering multiple factors such as the resource potential, local climate, land use and reservations, coastal reservations, access to resource locations, housing density, local climate and distance to transmission infrastructure, etc.

Therefore, all renewable energy resources were classified in to seven renewable energy zones where each zone has a specific topographical and resource characteristic. The probabilistic realization of the identified potential has been considered when estimating the final potential of each zone. The northern, north eastern and eastern zones have high potential for ground mounted solar, while northern zone has high potential for wind. The southern zone has development potential for both solar and wind with biomass. The central zone has potential for mini hydro and floating solar.

The final potential considered in planning studies for medium to large scale renewable energy projects are tabulated in Table 5.4 and the classification of zones considered in this study is shown in Figure 5.8.

Table 5.4 – Renewable Energy Potential Considered in Renewable Energy Zones

Renewable Energy Zone	Solar (MW)		Wind (MW)		Mini Hydro (MW)	Biomass (MW)	Total Renewable Energy Potential (MW)
	Ground Mounted	Floating	On Shore	Off Shore			
Northern	1,700	10	1,400	2,500	-	15	5,565
North Eastern	1,800	40	10	-	-	25	1,875
North Western	50	-	200	500	-	10	760
North Central	50	620	200	-	-	45	910
Eastern	1,200	30	-	-	-	30	1,260
Southern	400	100	50	1,000	-	60	1,560
Central	-	700	-	-	300	15	1,090
Total	**5,200**	**1,500**	**1,860**	**4,000**	**300**	**200**	**13,000**

The identified resources potentials for each type are planned to be developed following an economic order based on the resource's quality (energy yield, geographical staggering due to variability etc.) and infrastructure requirement (land, transmission infrastructure, access roads etc). In addition to the above zones small potential is identified from solar and biomass resources scattered around the island.

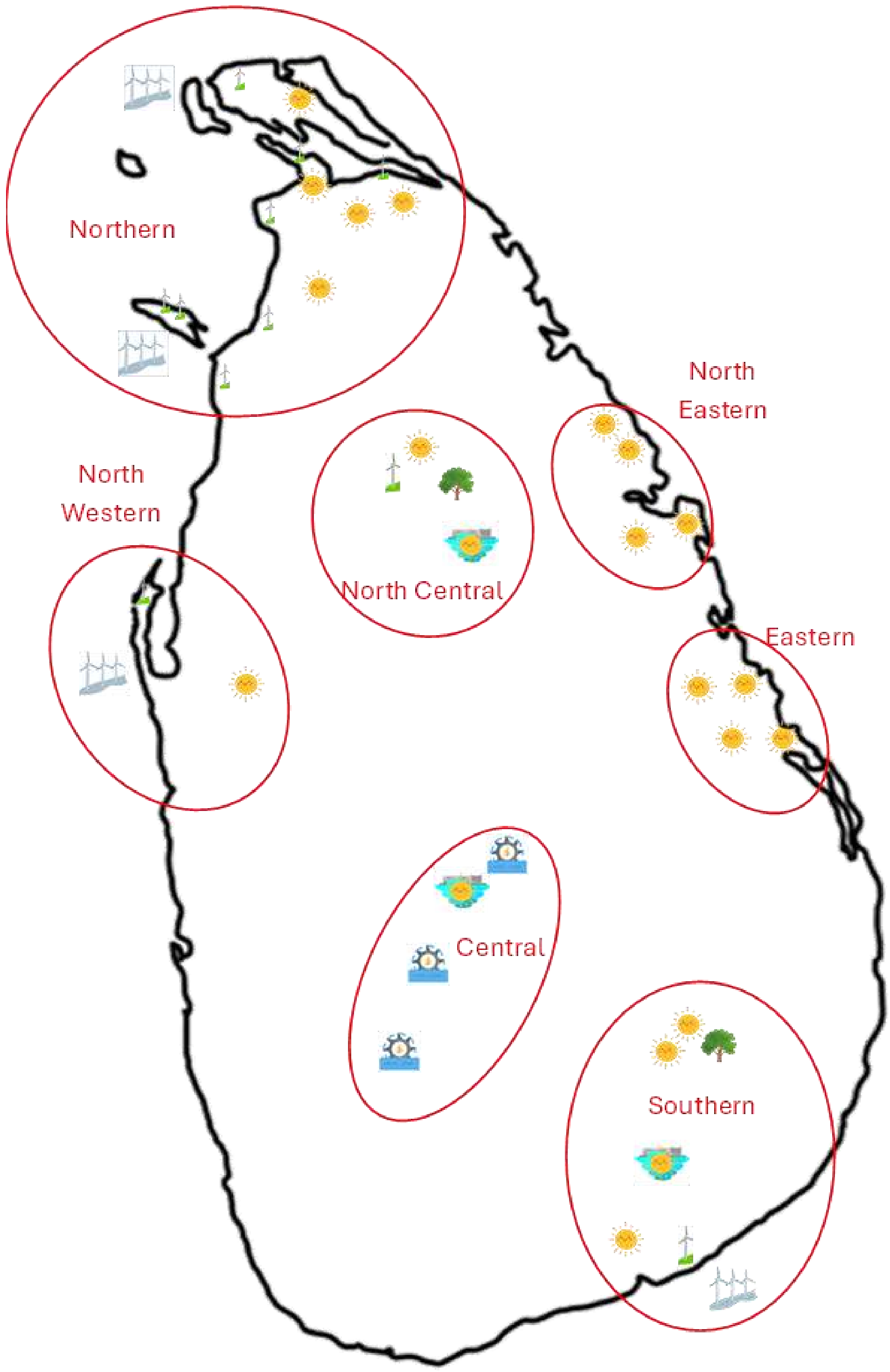


Figure 5.8 - Classification of Renewable Energy Zones

5.10 Operational Study for Renewable Energy Integration

The scale of wind and solar resource development currently being envisaged to meet the government policy targets will move the country's power system to phases where the integration challenges become much more significant requiring special operational, policy and investment based interventions.

As the major portion of the potential renewable additions is comprised of VRE, implications of VRE in different time frames covering capacity adequacy, transmission infrastructure development, system operational flexibility system stability and reliability are assessed. Therefore, an integrated approach combining resource assessment, capacity expansion planning, system operation analysis and transmission network analysis study components is conducted.

The Sri Lankan power grid, due to its relatively small and isolated nature, faces unique challenges when integrating variable renewable energy sources, such as solar and wind, which are inherently intermittent. Successfully incorporating these renewables into the grid relies heavily on the system's stability and operational flexibility. A system operation study is performed to investigate the implication on system operation to identify challenging operating conditions and potential solutions to mitigate the implications of renewable generation. Dispatchable power plants (both Major Hydro and Thermal plants) complement the non-dispatchable generation in meeting the electricity demand while maintaining the balance between supply and demand. Under high penetration levels of variable renewable energy, the dispatchable power plants are required to follow more cyclic operation and to provide fast ramping more regularly. Therefore, the technical constraints of the dispatchable power plants as well as the system flexibility level governs the ability of the system to operate under higher VRE penetration levels reliably.

Operation constraints are prominent specially during low load period such as weekends with large amount of wind, mini hydro and solar PV generation. During such constrained periods the large thermal units have to lower their output to a minimum or consider shutting down depending on network requirement and the start-up costs etc. Beyond such levels a surplus generation exists in renewable which has to be either curtailed or stored to maintain the supply demand balance of the system. According to the study results, the curtailment magnitude is likely to increase year by year to significant levels with the addition of the planned renewable energy capacities. The most severe impact on operation is observed during periods where low demand coincides with high renewable periods. Therefore, it is crucial that the system operator has adequate measures such as flexible generation, VRE curtailment and energy storage to maintain the supply demand balance throughout the year. Improved flexibility performance in both technical and contractual terms for thermal plants, introducing plants with the capability of fast ramping and frequent cycling is essential. Introduction of battery energy storage systems, pumped storage power plants and interconnections are envisaged as long term measures to enhance system flexibility.

High shares of inverter based non-synchronous renewable energy generation challenges the stable operation of the power system. As the inverter based generation does not actively contribute to the synchronous inertia or to the system strength, high instantaneous penetration levels of inverter based generation lowers the system's ability to withstand sudden imbalances and disturbances that can potentially lead to system failures. The grid integration study evaluates the transmission infrastructure development and the impacts of VRE integration on the stability and security of the transmission network under different operating conditions. The study has proposed the required transmission system development and strengthening measures for large scale renewable energy development. In addition to the storage requirement, batteries are proposed to provide fast responses required to manage the frequency under high penetration levels of variable renewable energy sources.

Parameters considered for planning studies of candidate other renewable energy technologies are given in Table 5.5.

Table 5.5 – Parameters of Other Renewable Sources

ORE Technology	Pure Capital Cost (USD/kW)	Capital Cost with IDC (USD/kW)	Annual Fixed O&M Cost (% of the capital cost)	Construction years
Solar (Large Scale)	849	904	1.5%	1.5
Solar (Distributed)	982	1,024	0.9%	1
Floating solar	1,244	1,325	1.5%	1.5
Onshore Wind	1,391	1,482	3.0%	1.5
Offshore Wind (Fixed Bottom)	3,781	4,201	3.0%	2.5
Offshore Wind (Floating)	5,238	5,821	3.0%	2.5
Biomass	1,782	1,899	4.0%	1.5
Mini hydro	1,840	1,959	2.5%	1.5

The estimated plant factors and respective specific cost of candidate ORE technologies are given in Table 5.6.

Table 5.6 - Estimated Plant Factors and Specific Cost of ORE Technologies

Technology		Plant Factor (Apprx.)	Specific Cost UScts/kWh
Solar (Large Scale)		20%-23%	5.58-6.42
Solar (Distributed)		16%-18%	7.87-8.86
Floating solar		19%	9.9
On Shore Wind	Mannar	38%-44%	5.32- 6.16
	Northern	34%-37%	6.33-6.89
	Puttalam	32%-35%	7.32-6.69
	Eastern	27%	8.67
Off-shore wind	Fixed	45%-50%	12.73-14.14
	Floating	45%-50%	17.63-19.59
Biomass		50%	6.41
Mini hydro		37%	8.09

5.11 Development of Grid Scale Energy Storages

Integrating variable renewable energy at grid scale as well as end-use sectors while providing reliable supply of electricity has brought much significance to the potential energy storage applications. Storage technologies are diverse and their applications are rapidly expanding globally. Their applications in power systems are growing and can range from energy shifting, frequency controlling, and renewable energy fluctuation controlling. The economic value of different technologies varies depending on the type of application, amount of energy required, amount of power required and the location of the application. High Energy density storage systems are suitable for performing energy shifting function in system operation whereas high power density storage technologies are suitable to provide fast power to manage instantaneous and momentary supply demand unbalances. To enable higher integration from variable renewable energy sources a mix of both these storage systems are required.

Battery energy storages and pumped hydro storages are two major storage technologies that has reached commercial level maturity at present. Other storage technologies such as compressed air energy storage, liquid air energy storage, thermal energy storage are at various development stages which could pay a pivotal role in the rapidly changing grid. Considering the inherent seasonality characteristics of wind energy resources, it is becoming important to evaluate the possibilities of seasonal storage. The development of Hydrogen storage is emerging as a new technology to perform energy shifting through seasons. Although large amounts of projects have been announced, commercial scale projects to develop green hydrogen is still at early stages of development.

Ceylon Electricity Board has identified the requirement of developing the pumped hydro power project as a long term solution to increase power system operational requirements. CEB is also currently embarking upon developing grid scale battery energy storages for the purpose of fast response flexibility and energy shifting requirements.

5.11.1 Grid Scale Battery Energy Storage Development

Battery energy storage applications in power systems are expanding globally and the technology costs are declining notably. Even though the scale of battery energy storages applications in power systems are small compared to pumped hydro storages, battery energy storages have a wide array of applications in all generation, transmission distribution and consumer end points. Given the range of applications, battery energy storages are employed to enhance the quality and reliability of supply of electricity.

The battery storage systems provide services in different time frames ranging from fast frequency support to energy arbitrage with economic dispatch. Also, it provides various support services for renewable energy grid integration. Lithium-ion type of batteries in power system applications are growing at present than the other forms of chemical batteries such as Flow batteries, Lead-based batteries and Sodium Sulphur batteries. Techno-economic assessment of the type of battery storage application and the type of battery technology is essential to identify effective storage solutions.

Ceylon Electricity Board has assessed the requirement of grid side application of battery energy storages with the introduction of large amount of intermittent and non-synchronous generation in to the power system. A pilot project of 5 MW/10 MWh is to be connected to the Hambantota Grid Substation with Korean government assistance. The first major battery energy project of 100 MW/ 50 MWh is expected to be developed in the western region. The Kolonnawa Grid substation has been earmarked for the project and its primary purpose is to provide frequency regulation and fast frequency response services. In addition to this the project is expected to assist during Colombo power restoration in the event of a blackout. The 50 MWh storage capacity of the project may be updated to reflect the actual site conditions.

Majority of the other battery energy storage systems are designed for energy shifting purposes, mainly to provide peak shaving during the night peak. They shall have a 4-hour duration for storage and may provide frequency related services as a secondary objective. All battery energy storage facilities are expected to have the dispatchable capability to operate according to the dispatch instructions of the National System Control Centre. The planning studies have considered 80% Depth of Discharge capabilities from all battery energy storages and Table 5.7 shows the important paraments of candidates considered for the planning studies.

Table 5.7 – Parameters of Battery Energy Storage Systems

Duration	Capital Cost Pure (USD/kW)	Capital Cost with IDC (USD/kW)	Construction Period (Years)	Economic Life (Years)
2 Hour	897	955	1.5	10
4 Hour	1,456	1,551	1.5	10
8 Hour	2,587	2,755	1.5	10

Source : GenCost 2022-23, Final Report, Australia's National Science Agency, CSIRO, July 2023

5.11.2 Pumped Hydro Storage Development

Being a matured technology, pumped hydro storage currently accounts for nearly 97% of the storage applications in power systems worldwide. Primary function of pumped hydro storage was to provide peaking capacity releasing the stored energy. However, the technology has now evolved to provide enhanced services to enable flexible grid operation specially with renewable energy integration.

CEB conducted the study in 2014 on exploring peak power generation options including pumped storage power plant. The study titled "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" [19] was done with the technical assistance from JICA. During the study, Pumped Storage Power Plants were identified as a possible peaking option with its load following capability, power plant characteristics, environmental, social and economic considerations.

Pumped storage power plants are large scale storage medium that is able to serve several important secondary purposes other than providing the peaking power. Pumping operation of off-peak period enables the storage of surplus renewable energy that otherwise would have curtailed due to power system operational limitations. The new adjustable speed technology enables greater flexibility for pumping operation and it enables the frequency regulation functions and stability improvement by fast reaction to system supply and demand fluctuations. Moreover, the pumping operation during low load periods enables the operation of base load power plants in the system at their most efficient operating points. The renewable energy grid integration studies have identified significant renewable energy curtailment requirement with planned renewable energy capacities. The curtailments are mainly due to the demand pattern of the country and seasonality and variability of variable renewable energy sources. A large scale pumped hydro storage will enable greater utilization of renewable energy resources while alleviating system operational challenges.

The scope of the Study included the identification of most promising candidate site for the future development of pumped storage power plant. At the initial stage, the study conducted by JICA and CEB identified 11 potential sites for the development of 600 MW pumped storage power plant and all the sites were investigated and ranked in terms of Environmental, Topographical, Geological and Technical aspects. The preliminary screening process identified three promising sites for the detailed site investigations. According to the ranking, Halgran Oya, Maha Oya and Loggal Oya which were located in Nuwara Eliya, Kegalle and Badulla districts were selected as the most suitable sites for future development. After the detail site investigations carried out for the above three sites, the study concluded that the Maha Oya site location as the most promising site for the development of the future pumped storage power plant.

Another new site location for the PSPP plant was proposed by the Electricity Sector Master Plan Study completed in 2018 with the assistance of JICA. The proposed site is located in the Kandy district adjacent to the Victoria reservoir. This scheme will utilize the existing Victoria reservoir as the lower pond and an existing irrigation pond located at Wewathenna (on the eastern side of Victoria reservoir) as the upper pond, after expansion. The initial proposed capacity of 1,400 MW was scaled down to 700 MW considering the actual geological conditions at the project site, during the phase I of the pre-feasibility study and the feasibility study for a pumped storage power plant project from ADB funds in year 2023 [20]. Hence the per unit construction cost of Wewathenna had also elevated, which resulted in lower priority among available sites.

Accordingly, the same study concluded that the 600 MW Maha Oya site was the best option for development of the first pumped storage power plant considering the costs, geological conditions, construction workability, and natural and social environments. Figure 5.9 below illustrates the proposed sites under previous studies.

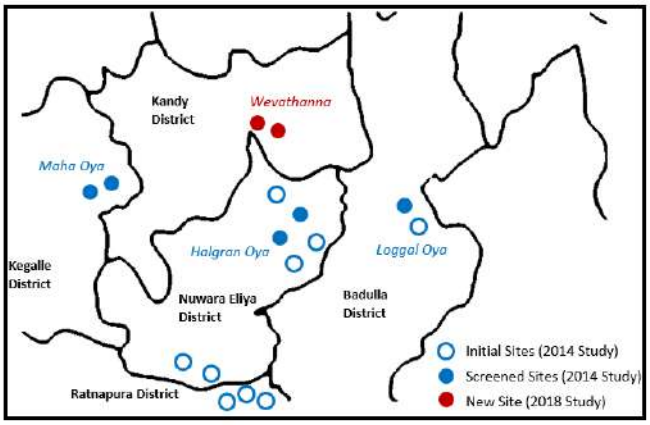


Figure 5.9 - Three Selected Sites for PSPP after Preliminary Screening

Table 5.8 shows the estimated capital cost of development for proposed sites locations final study in year 2023. Both projects are designed to have storage sufficient for 6 hours full load operation. The detailed feasibility study is presently in progress for the 600 MW Maha Oya Pumped Storage Power Plant. In order to preserve the inertial response during pumping operation, all three units are to be developed as fixed speed pump storage units.

Table 5.8 – Parameters of Proposed PSPP Sites

Proposed Project	Units and Capacity (MW)	Capital Cost Pure (USD/kW)	Capital Cost with IDC (USD/kW)	Construction Period (Years)	Economic Plant Life (Years)
Maha Oya Pumped Storage	3 x 200 MW	1,438	1,512	5.0	50
Wewathenna Pumped Storage	2 x 350 MW	1,768	1,863	5.0	50

CHAPTER 6
INTERCONNECTION OPTIONS

6.1 Background

Interconnections between two power grids involve the physical and technical integration of their infrastructure, such as transmission lines and transformers, to enable the exchange of electricity. These connections ensure that the grids operate with better load balancing, improved reliability, and enhanced efficiency. By facilitating energy trading and sharing resources, interconnections support the integration of renewable energy sources and provide economic benefits through cost savings and optimized resource usage. Regulatory frameworks and agreements govern these interconnections, ensuring safety, compatibility, and equitable cost-sharing.

South Asia is rich in energy resources which are unevenly distributed among the countries of the region. Cross border electricity trade opportunities through bilateral or multilateral or market-based trade would be beneficial for countries in the region.

Sri Lanka being an islanded nation, has limited options of interconnectivity other than through India. In 2002, NEXANT with the assistance of United States Agency for International Development (USAID) carried out the Pre-feasibility study for Electricity Grid Interconnection between India and Sri Lanka. It was a first step in developing the project concept and was expected to serve as the basis for future technical and economic analysis.

In 2006, POWERGRID, India reviewed and updated the study with USAID assistance. Governments of India and Sri Lanka signed a Memorandum of Understanding (MOU) in 2010 to conduct a feasibility study for the interconnection of the electricity grids of the two countries. This feasibility study was carried out jointly by CEB and Power Grid Corporation Indian Limited (POWERGRID). The main objective of the feasibility study was to provide the necessary recommendations for implementation of 1,000 MW HVDC interconnection project. Various Line route options and connection schemes were analysed during the pre-feasibility studies. Technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka have also been considered.

Consequently, several India-Sri Lanka Joint Technical Team studies has been conducted with changes in routes and options on overhead as well as undersea sub marine cable options. Furthermore, ADB funded study on Economic and Financial Feasibility Assessment of Proposed Sri Lanka - India Interconnection Project was conducted [21].

6.2 Infrastructure Development

Both synchronous and asynchronous options were initially studied for interconnecting the Indian and Sri Lankan grids. However, due to concerns about uncontrolled power transfer and fault propagation affecting system security and stability, an HVDC link was chosen in the 4th Joint Working Group (JWG) meeting for its controlled power flow and stable operation benefits.

The initial feasibility study concluded a proposal of 130 km 400 kV HVDC overhead line segment from Madurai to Indian sea coast, 120 km of 400 kV Under-Sea cable from Indian sea coast to Sri Lankan Sea coast, 110 km Overhead line segment of 400 kV from Sri Lankan sea coast to Anuradhapura and two converter stations at Madurai and Anuradhapura. During the India-Sri Lanka Joint Technical Team studies initiated in year 2017, it was decided to shift the HVDC station in Sri Lankan side from Anuradhapura to New Habarana. Further, after site survey it was found that overhead interconnection is feasible without any submarine cable.

Initially the Interconnection was planned to be developed from as HVDC overhead link between Madurai (India) and New Habarana (Sri Lanka) with, 2x500MW. However, in year 2023 due to the additional benefits of harnessing the wind resources in Mannar region the HVDC termination in Sri Lanka was shifted to Mannar. Furthermore, complexities of operation and maintenance activities in overhead lines in the sea required to further analyze the undersea cable option.

Given these considerations, an asynchronous interconnection between the Indian and Sri Lankan electricity grids through a ±320kV , 2x500 MW HVDC link from Madurai New (India) to Mannar (Sri Lanka) with HVDC terminals based on Voltage Source Converter (VSC) technology has been considered by the JWG. The schematic diagram of the proposed interconnection is illustrated in Figure 6.1.

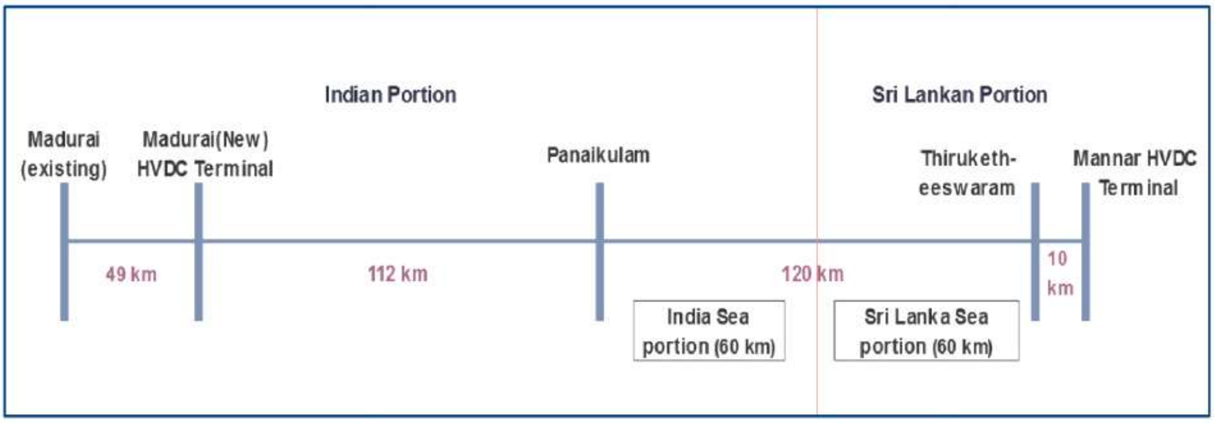


Figure 6.1 - Schematic of Sri Lanka India Interconnection Option

Accordingly, in phase-1, 500 MW HVDC is planned to be implemented and phase-2 comprising of 2nd 500MW HVDC would be taken up at a later stage. VSC based HVDC can additionally act as a STATCOM and take care of the required dynamic reactive power support for grid stability and renewable integration also. Further, the uncertainty of adequate short circuit level due to intermittent and variable nature of renewable energy can also be addressed by VSC based HVDC.

The Total cost for the development of 1st phase of HVDC link between Madurai and Mannar using undersea cable option is USD 1,225 Million. During this phase the cables and design shall be developed to allow 1000 MW power transfer in future. The 2nd phase shall be developed at a later stage based on the requirement of additional power exchange between the two countries with the installation of additional HVDC terminals at Madurai(New) and Mannar.

6.3 Cross border electricity trade options

Over the years, Sri Lanka has signed several agreements and is part of regional cooperation among South Asian countries. SAARC Framework Agreement for Energy Cooperation (Electricity), Memorandum of Understanding for establishment of BIMSTEC grid interconnection, and intergovernmental arrangements with India on cooperation in power sector enabling the strategic and political framework for Cross Border Electricity Trade (CBET).

Indian economy is going through a phase of sustained growth and continuous transformation. Over the last 5 years, the energy requirements in the country grew at a CAGR of 3.3%. Whereas the peak demand of power increased CAGR of 5.7%. The generation mix comprising of higher share of thermal capacity with fairly uniform generation round the year, provides relatively stable supply throughout the year. However, higher deficits in energy demand are observed during the months of March to October and the deficit drops during the months of November to February. The electricity sector in India is dominated with Long-term power contracts. Power purchase agreements (PPAs), with tenures of 25 years, comprise 87.5% of the overall traded volumes. While providing investors with certainty over a long duration and de-risking from price volatility, the growing implications of these PPAs are in discussion to aid the financial viability of state distribution companies. On the other hand, Indian short term power market covers contracts of less than one year and constitutes ~12.5% of total power supply.

The Cross-Border Electricity Trade (CBET) commenced in the short term power market through the Day-ahead Market. This is a significant achievement as it opens avenues for other countries in South Asia for electricity trade through market access. With Nepal spearheading the day-ahead market participation initially through both import and export of power. Recently, Bhutan has commenced buying power from the Indian power exchange to meet the dry season deficits.

For cross border trade with India, Sri Lanka can participate in Indian power exchanges and enter into bilateral agreements with Indian generating companies and utilities. However, the regional cross border power trade is gradually expected to transition towards a trilateral power trade model wherein, a third country will be offering wheeling/ transmission facilities for the buying and selling countries which may not be interconnected geographically.

The interconnection may also provide access to Indian ancillary market in the future. The ancillary market is currently evolving in India and participation is only limited to domestic generators. However, given the gradual opening of various market segments to cross border power trade, it is likely that the ancillary markets may also be opened for cross border trade in future.

6.4 Bilateral Contracts

Sri Lankan utilities could enter into bilateral power trade arrangements with Indian generating companies and offtake power from Indian grid. In addition to the price offered from Indian generating companies, Transmission (PoC) charges for injecting power at Tamil Nadu, System losses at approximately 3.91% and System operations charges are to be considered to derive the landed cost at HVDC terminal in India side. In recent years, to support grid integration of renewables, India has been focusing on innovative renewable energy procurement approaches for reducing generation intermittency by utilizing the flexibility options available and promoting energy storage systems. Following bilateral options are considered for

1. Stand Alone Hybrid Projects
2. Assured Peak
3. Round the Clock (RTC)

6.4.1 Stand Alone Hybrid Projects

Standalone hybrid projects consist of blending generation from solar and wind sources at evacuation point to ensure relatively smooth diurnal generation as compared to the standalone solar or wind projects. Average tariff for solar-wind hybrid projects from year 2020 – 2023 has been 3.36 UScts/kWh which results in a landed cost at India HVDC terminal around 4.06 UScts/kWh.

6.4.2 Assured Peak

The energy storage systems are deployed together with solar and or wind projects to ensure firm supply during peak hours, typically 6 hours in a day. Assured peak power supply projects ensures firm supply of dispatchable renewable power and meets the demand pattern of the consumers during peak demand hours (morning and evening peak) at a competitive tariff. Two-part tariff is applicable for these projects with peak tariff and off peak tariff. Usually, the off peak tariff is set at a flat tariff payment, while the peak tariff is discovered through the auction. The average peak hours tariff for assured peak projects from has been 7.88 UScts/kWh which results in a landed cost at India HVDC terminal around 8.76 UScts/kWh. The average off peak hours tariff for assured peak projects has been 3.60 UScts/kWh which results in a landed cost at India HVDC terminal around 4.31 UScts/kWh. A minimum gap of 12 hours is to be maintained between the last peak hour of any day and the first peak hour of the day subsequent to that day

6.4.3 Round the Clock (RTC)

Renewable energy is complemented with stable power from conventional sources such as thermal, hydro or energy storage systems ensuring round-the-clock (RTC) power supply and provide firm power to the consumers. In RTC projects, a minimum 51% of energy shall be offered from renewable energy sources annually. The 51% shall also include offer from the energy storage systems, provided renewable energy sources were used to store energy in the storage system. The average tariff for round-the-clock projects has been 3.96 UScts/kWh which results in a landed cost at India HVDC terminal around 4.68 UScts/kWh. They typically supply the contracted capacity in the Round the Clock manner, keeping at least 90% availability annually along with 90% availability on monthly basis for at least 11 months in a contract year.

6.5 Indian Power Exchange

In India, three Power exchanges, namely the Indian Energy Exchange (IEX), Power Exchange of India Limited (PXIL), and Hindustan Power Exchange Ltd. (HPX) are operated. They provide electronic platforms allowing electronic bidding from across the country and undertake price discovery through anonymous competitive bidding mechanism through various types of products. Out of these, IEX commands a major market share of over 98 % of the traded volume. IEX has a robust ecosystem of 7,600+ participants located across 28 States and 8 Union Territories in India.

The market products available Indian Energy Exchange are Day Ahead Market, Term Ahead Market (Intra Day, Day Ahead Contingency, Daily, Weekly), Real Time Market, Renewable Energy

Certificate and Green Market. The Green Market has options for Green Day Ahead Market and Green Term Ahead Market in which trade is offered through only renewable energy sources.

In year 2021 Indian Energy Exchange has launched the Cross Border Electricity Trade on its platform. This is an initiative for the exchanges to expand their power markets beyond India to the South Asia region towards building an integrated South Asian regional power market. Nepal and Bhutan have started power exchange through IEX and Bangladesh is presently in discussion to enter the market. Presently Day Ahead Market is open for cross border electricity trade and other markets may gradually be opened up in future.

6.5.1 Day Ahead Market

In the Day Ahead Market electricity is traded for 15 minute time blocks in 24 hours of next day starting from midnight. The prices and quantum of electricity to be traded are determined through a double sided closed auction bidding process.

Participants enter bids for sale or purchase of power for 15 minute time blocks delivery on the following day. At the end of the bidding session, bids for each 15 minute time block are matched using the price calculation algorithm. Market clearing price (MCP) and Market clearing volume (MCV) are determined for each block of 15 minutes as a function of demand and supply which is common for the selected buyers and sellers. Based on the reserved transmission capacity intimated by National load dispatch center of India, IEX recalculates MCP and MCV as well as area clearing price (ACP) and area clearing volume (ACV).

The procurement of power from Day ahead Market from India shall consider additional cost components on Transmission (PoC) charges for injecting power at Tamil Nadu, System losses at approximately 3.91%, IEX Transaction charges, trading margin charged by the trader and System operations charges in addition to the market clearing price. The derived the landed cost at HVDC terminal in India based on data from year 2022 is as tabulated in Table 6.1.

Table 6.1 - Landed Cost from India from Day Ahead Market (UScts/kWh)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	3.17	3.91	11.54	15.98	12.50	14.28	9.77	7.46	8.46	5.08	5.26	4.35
2	3.06	3.77	10.58	15.59	11.09	12.18	7.85	6.38	7.27	4.81	4.99	4.11
3	2.96	3.63	9.28	15.20	10.10	10.52	6.57	5.70	6.57	4.55	4.82	3.94
4	2.94	3.56	8.27	14.82	9.43	9.31	5.97	5.43	6.06	4.35	4.71	3.92
5	3.04	3.72	8.38	14.58	9.28	9.95	5.81	5.66	6.24	4.55	4.94	4.23
6	3.72	4.66	11.19	15.05	9.35	9.43	6.81	7.64	7.67	5.19	5.86	5.28
7	5.13	8.62	16.62	15.25	8.93	8.45	7.73	8.61	9.79	5.97	6.85	7.80
8	6.27	13.25	17.96	13.69	7.32	6.13	7.31	7.49	7.80	5.80	7.91	11.74
9	7.14	10.73	10.72	11.79	6.04	4.77	5.55	5.82	5.81	4.98	7.40	11.13
10	7.28	8.35	9.51	11.48	6.00	4.43	4.96	5.34	5.19	4.62	7.13	10.64
11	6.78	7.99	9.98	11.60	6.40	4.87	4.70	4.96	4.97	4.45	6.69	9.68
12	5.97	7.29	9.42	11.28	6.94	5.29	4.54	4.90	4.99	4.24	6.38	8.17
13	5.14	6.12	8.90	10.31	6.92	5.62	4.44	4.59	5.00	4.05	5.86	6.88
14	4.29	4.77	7.46	9.50	7.20	5.85	4.26	4.30	4.69	3.89	5.58	5.85
15	4.03	4.41	8.61	11.20	8.64	7.24	4.60	4.81	5.44	4.17	5.87	6.22
16	4.36	4.72	10.02	12.72	9.90	8.65	5.43	5.59	6.52	4.57	6.30	7.08
17	4.85	5.78	12.16	13.61	9.65	7.73	5.69	6.27	7.14	5.09	6.84	9.43
18	6.24	7.82	11.94	14.00	9.31	6.82	5.93	6.31	8.14	6.54	9.18	11.03
19	8.82	10.10	14.93	14.74	9.57	7.52	9.10	9.23	12.32	11.94	11.93	12.68
20	7.44	9.35	16.57	15.27	11.36	12.69	13.46	13.13	15.21	11.60	8.47	10.79
21	5.58	6.63	12.83	14.79	11.32	12.77	13.86	12.82	12.76	7.12	6.93	7.25
22	4.86	5.58	11.88	15.21	12.52	14.16	13.77	12.47	11.65	6.06	6.47	6.21
23	4.10	4.73	11.38	15.25	13.04	14.55	13.42	11.57	10.91	5.61	6.48	5.26
24	3.48	4.14	11.65	15.92	12.95	14.28	12.20	9.67	10.01	5.17	5.59	4.68

CHAPTER 7
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

7.1 Background

The long term generation planning exercise investigates avenues to develop the electricity generation system to meet the future electricity demand by considering all potential and proven sources of thermal and renewable energy generation. Several factors are taken into account in this process of evaluating and selecting the most suitable power generating options. Policy targets of the government, technical and economic characteristics of generating technologies, requirements of the network in terms of system security and system operation, exploitable renewable energy resource potentials, environmental obligations as well as transition strategy towards carbon neutrality are among several factors considered in this exercise.

The policies and guidelines relevant to power sector such as "The National Energy Policy and Strategies of Sri Lanka" [22], "General Policy Guidelines on the Electricity Industry" [23] and "Draft Grid Code of CEB Transmission Licensee" [24], are taken into consideration in the planning process.

The Long Term Generation Expansion Plan is the outcome of the optimization process constrained with above mentioned factors. The policies and guidelines that were considered and methodology adopted in the process is described in this Chapter and depicted in Annex 7.1.

7.2 Generation Planning Code

The Least Cost Generation Expansion Planning Code was published in April 2011, to act as basis for conducting generation planning activities. The code represents objectives, planning period, frequency of update, planning boundaries, planning criteria, establishment of economic parameters, the development of base case with sensitivity analysis and other policy and scenario analysis to be considered when preparation of the Least Cost Generation Expansion Plan.

All elements of the Least Cost Generation Expansion Planning Code are contained in the Draft Generation Planning Code under the Grid Code issued by the Transmission Licensee in September 2023, which has been updated from the Grid Code issued by PUCSL in March 2014.

7.3 National Energy Policy and Strategies

Ministry of Power and Energy updated the National Energy Policy & Strategies of Sri Lanka in the Gazette Extraordinary No. 2135/61 dated 2019-08-19 after reviewing and revising the National Energy Policy and Strategies of Sri Lanka published in 2008. The main objective of the National Energy Policy and Strategies declared is to ensure convenient and affordable energy services are available for equitable development of Sri Lanka using clean, safe, sustainable, reliable and economically feasible energy supply. This Policy is formulated in alignment with the future goals of Sri Lanka, current global trends in energy and the Goal 7 of the Sustainable Development Goals of the United Nations. This policy is expected to pave the way to realize the vision of Sri Lanka in achieving carbon neutrality by 2050. The "National Energy Policy and Strategies of Sri Lanka" is elaborated in three sections as follows:

a) **The National Energy Policy**, stating the ten pillars of the policy framework
b) **Implementing Strategies**, describing the specific strategies to implement the policy
c) **The Results Delivery Framework**, elaborating the specific actions, milestones and the institutions responsible

The National energy policy stands on following ten pillars, rooted in the broad areas impacting the society, economy and the environment to counter balance the forces through enhanced equity, security and sustainability.

i. Assuring Energy Security
ii. Providing Access to Energy Services
iii. Providing Energy Services at the Optimum Cost to the National Economy
iv. Improving Energy Efficiency and Conservation
v. Enhancing Self Reliance
vi. Caring for the Environment
vii. Enhancing the Share of Renewable Energy
viii. Strengthening the Governance in the Energy Sector
ix. Securing Land for Future Energy Infrastructure
x. Providing Opportunities for Innovation and Entrepreneurship

During the Preparation of Long Term Generation Expansion Plan 2025-2044, due consideration is given to salient features of the National Energy Policy pillars considering the Implementing Strategies and specific milestones as follows.

7.3.1 Assuring Energy Security

a) Diversity of energy resources is met by introducing natural gas to the existing mix of coal, hydro, furnace oil and other renewable resources. Constrained with the Policy Guidelines, coal and furnace oil/diesel will be phased out leaving natural gas and renewables to be the main resources. As the renewable resource becomes dominant in the future, achieving energy security through renewable resources will be looked at with a different perspective.
b) A liquefied natural gas (LNG) terminal of optimum size and technology would be established at the west coast, being the most suitable location. Considering the impact to the country's energy security, operation of the first terminal and LNG procurement shall be kept under state control.
c) Percentage of installed power generation capacity from a single imported fuel shall not exceed 50% of the total installed firm capacity to safeguard against geopolitical uncertainties and fuel price shocks.
d) National requirements of electricity will be met with proven generation technologies and fuel sources.

7.3.2 Enhancing Self Reliance

a) Indigenous oil and natural gas resources will be explored. Commercial scale exploitation will be strategically phased, giving due consideration to higher future value and possible use in the future as a locally available fuel source to derive cleaner futuristic energy sources such as hydrogen.
b) Renewable energy resources will be exploited based on a priority order arrived at, considering economics, technology and quality of each resource.

c) Wind and solar is identified as the most promising renewable energy resources after hydropower and highest priority is given to develop wind and solar in future years.

7.3.3 Caring for the Environment

a) Energy supply from cleaner sources and technologies will be encouraged to minimize harm to the local and global environment, while taking into consideration both the impacts on the national economy and the long-term environmental benefits.
b) Nationally Determined Contributions (NDCs) to global emission reduction goals will be made to meet the National emission reduction obligations as agreed.

7.3.4 Enhancing the Share of Renewable Energy

a) Energy supply from renewable energy resources in the country's energy mix will be increased to reduce pressure on foreign exchange, as a means of engaging the local community in the energy industry and to attain sustainability.
b) Research will be conducted to overcome adverse impacts of renewable energy absorption to the power system from intermittent sources such as wind and solar energy.
c) Effective forecasting technologies for renewable resources will be introduced so that optimum use of the resource could be realised.
d) Energy storage solutions will be encouraged for firming intermittent renewable sources, voltage and frequency regulation, local grid support, peak shaving and improving grid resilience.

7.3.5 Securing Land for Future Energy Infrastructure

a) Suitable sites to locate future energy infrastructure (power plants, refineries, terminals) will be strategically earmarked in advance following preliminary feasibility studies, so that the public can avoid using such sites, resulting in minimal relocation and social impacts at the time of actual development.
b) Best sites to locate large scale renewable energy infrastructure such as wind and solar farms would be identified in advance and marked on a master plan so that they can be developed as large concentrated facilities in phases.

7.4 General Policy Guidelines on the Electricity Industry for the PUCSL

Section 5 of Sri Lanka Electricity Act, No 20 of 2009 defines Minister of Power has the power to formulate the General Policy Guidelines on Electricity sector for the Public Utilities commission. The General Policy Guidelines on the Electricity Industry 2021 (issued in January 2022), read together with the National Energy Policy and Strategies of Sri Lanka (gazetted in 2019) is taken as the applicable policy guidelines in preparation of LTGEP 2025-2044.

Long Term Generation Expansion Plan 2025-2044 has incorporated the instructions given in the General Policy Guidelines on the Electricity Industry, with emphasis given on following clauses.

Clause 8

The GOSL has long recognized the need for transforming the country's electricity sector from its traditional centralized and vertically integrated structure relying on a few relatively large capacity thermal power plants and collection of storage hydropower plants to one made up of numerous independent operators producing electricity including variable renewable energy (VRE). Several policies have been implemented by the GOSL towards achieving this objective. High integration of renewable energy and achieving a clean and carbon reduced energy economy are priority policy objectives for GOSL.

Clause 9

The GOSL has set the targets of achieving 70% of electricity generation in the country using renewable energy sources by 2030 and carbon neutrality in power generation by 2050, and has decided to cease building of new coal-fired power plants. The Cabinet of Ministers has approved these two policy elements that shall form the basis of Sri Lanka's future electricity capacity expansion planning. Further, new addition of firm capacity will be from clean energy sources such as regasified liquefied natural gas (RLNG).

Clause 15

Addition of new generation facilities and expansion of existing generation facilities will be carried out according to the Least Cost Long Term Generation Expansion Plan (LTLGEP) approved by the PUCSL in accordance with the provisions of Section 43 of the Sri Lanka Electricity Act. LCLTGEP recognizes the need to add adequate generation capacity to meet the growing electricity demand of the country while ensuring reliability and quality of electricity supply as determined by the PUCSL from time to time in consultation with the licensees

Clause 16

Considering the major policy target of producing electricity using indigenous VRE resources energy storage options such as Pumped Hydroelectric Energy Storage (PHES) and Battery Energy Storage

Clause 23

Electricity generation using renewable resources such as solar and wind does not result in emission of greenhouse gases or local air pollution. The GOSL will give priority to developing renewable energy that is both indigenous and environmentally friendly to achieve its target of 70% renewable based electricity production by 2030. The planned future renewable energy portfolio will include onshore and offshore wind power, land based and floating solar PV as well as rooftop solar PV, micro hydro and biomass.

7.5 Thermal Power Plant Specific Cost Calculation

In the specific cost calculation methodology, investment cost is assumed as an overnight cost to occur at the beginning of the commissioning year and annual costs such as fixed and variable operation, maintenance and repair costs and fuel costs are discounted to the beginning of the commissioning year. Energy is calculated for each year of operation over the life time for various plant factors. Present value of specific energy cost of thermal plants is calculated for a range of plant factors. The specific cost curves reveal how different technologies perform at different plant factors. Specific cost calculation methodology is given in Annex 7.2.

7.6 Planning Software Tools

State of the art optimization and simulation models are used in the detailed generation planning exercise. Internationally accepted planning methodologies, wherever possible, are adopted during the formulation of the Long Term Generation Expansion Plan.

The Stochastic Dual Dynamic Programming (SDDP) and OPTGEN software tools developed by PSR (Brazil) were extensively used in conducting the system expansion planning studies to determine optimal Long Term Generation Expansion Plan. The Time Series Lab (TSL) software, developed by the same company, is utilized to generate future probabilistic scenarios based on satellite data for variable renewable energy (VRE) sources. This approach enhances the model's reliability compared to using a fixed VRE generation profile for the entire horizon.

7.6.1 Stochastic Dual Dynamic Programming (SDDP)

Stochastic Dual Dynamic Programming (SDDP) model is an operation planning tool developed by PSR (Brazil) which simulates the hydro and thermal generation system to optimize the operation of hydro system. 20 years of historical inflow data for existing, committed and candidate hydro plants were taken into account by the model to stochastically estimate the future inflow patterns and then simulates with total system to estimate energy and capacity availabilities associated with plants. Hydro plant cascade modelling and reservoir level detail modelling has been done to accurately represent the actual operation. Maximum of hundred scenario simulations could be considered in the model to represent the stochastic nature of hydrological conditions. To observe the operational patterns of the future generation system and to identify any operational issues, SDDP was used to simulate the hourly operation considering the least-cost stochastic operating policy of the hydrothermal system of the country, taking into account the following main inputs:

a) Operational details of hydro plants (irrigation requirements, limits on storage and turbine outflow, spillage, etc.)
b) Detailed thermal plant modelling (unit commitment, fuel contracts, efficiency curves, fuel consumption constraints, multiple fuels, ramp rates, startup capabilities etc.)
c) Renewable resource profiles and associated renewable generation plant modelling
d) Modelling of energy storage devices connected to the grid considering hourly time steps
e) Operational constraints of the system
f) Hourly demand variation levels

The modelling and simulations are performed to identify the operating patterns of the conventional power plants, system flexibility issues and the implications of variable renewable energy on the operation of conventional plants including energy storage solutions such as pumped hydro storage and battery energy storage in hourly resolution.

7.6.2 OPTGEN Software

OPTGEN software with the in-built SDDP module, developed by PSR (Brazil) is a long term expansion planning model which is used to determine the least cost sizing and timing decisions for construction and reinforcement of generation capacities and transmission network. OPTGEN optimizes the trade-off between investment costs to build new projects and the expected value of operative costs obtained from SDDP, the stochastic dispatch model. The Software is capable of modelling Other Renewable Energy Sources and is considered for optimization. In order to solve the expansion problem, OPTGEN model uses advanced optimization techniques of mixed-integer programming.

7.6.3 TSL Software

In the previous iterations of planning studies only the stochastic modelling of hydro inflows was considered. In order to present the intermittent nature of VRE sources and the correlation of hydro inflows, wind and solar irradiance, PSR has developed TSL, a separate software for the integrated generation of inflow, wind, and solar scenarios. The software is capable of generating future probabilistic VRE scenarios that may represent the spatial correlation with hydro inflows or any other random variables.

7.7 Modelling of Hydropower Development

Hydro resource is one of the main indigenous sources of energy and lifetime of a hydropower plant is longer compared to the other alternative sources. Sri Lanka has already developed almost all of the economically feasible hydro power projects in the country and few minor projects remain at their initial feasibility study level due to the inability to justify economically. Therefore, these hydro plants are considered separately outside the LTGEP. In this alternate process, economic analysis is carried out for each project with the consideration of avoided thermal plant. Then, technical feasibility studies and environmental impact assessments are processed for economically feasible projects. Once all these requirements are fulfilled and funds are committed, the project is incorporated to the LTGEP as a committed plant. At present only Moragolla hydropower project are considered as committed.

7.8 Modelling of Other Renewable Energy

The LTGEP 2025-2044 includes a significant amount of renewable energy resource development including wind and solar resources. Therefore, accurate representation of the important characteristics of each renewable energy resources is very important in the planning process. The OPTGEN, SDDP and TSL software packages used in this planning exercise are developed to capture the characteristics of renewable energy resources in the capacity expansion planning exercise in a more effective manner.

The main ORE technologies of mini-hydro, wind, solar and biomass were modelled based on actual resource characteristics as applicable for the generation planning exercise. As the major portion of the future renewable additions is comprising of variable renewable energy sources such as wind and solar PV, the modelling work has captured the variability, uncertainty and seasonality characteristics.

7.9 Modelling of Energy Storage Systems

Due to the policy requirement of achieving 70% renewable energy by 2030 and carbon neutrality in power sector by 2050, large scale energy storage systems are required to be added to the system. Two major types of storage systems modelled in the planning studies are pumped hydro storage and battery energy storage systems.

SDDP allows the modelling of pumped storage power plant with turbining and pumping operations considering its upper and lower reservoir characteristics. Battery energy storage systems are modelled in SDDP with their capacity and energy characteristics. Detailed characteristics such as state of charge, maximum depth of discharge, charging and discharging efficiencies and regulation time is considered in modelling. Energy storage is mainly utilized for time shifting of excess generation from renewable energy sources in low load periods instead of curtailing the excess generation. In addition, energy storage will also be utilized to provide other services such as ramp support/frequency regulation, renewable capacity firming, etc.

7.10 Modelling of Interconnection

The electricity interconnection between India has been modelled to capture both bilateral contracts as well as market operations of the Indian power system. Interconnection flow is dependant on the load marginal cost of the two countries. Handling fee of the interconnection is separated from the operation and is considered as a capital cost for the project.

7.11 Assessment of System Operational Capability

It is essential that the proposed development plan provides operational capability to the National System Control Centre, to operate the power system in a secure and economical manner, in both normal and contingency situations. In order to operate a stable power system in a high VRE system, a minimum synchronous generation penetration limit is required to be assessed. For long term planning studies, a maximum allowable limit of 75% of System Non-Synchronous Penetration from electricity demand has been considered during this planning horizon. In actual operation, this penetration level is expected to increase gradually as the power system demonstrates stable performance at the planned SNSP limits.

Designing and developing a stable and a resilient power system is essential to withstand both internal and external disturbances to the operation. Important attributes such as adequate synchronous inertia, frequency/voltage control capabilities and power failure restoration capabilities have been considered in preparing the development plan. Dynamic Probabilistic Reserve (DPR) developed by PSR is used to capture the additional reserve requirement requires to manage the challenges posed by the increasing penetration of renewable energy sources in power systems. This increases the generation reserve requirements and ensure that the grid remains reliable and resilient, even as the energy mix becomes more variable and uncertain.

As the system is transitioning towards higher shares of non-dispatchable intermittent variable renewable energy sources with higher degree of variability and uncertainty, ensuring the adequate operational flexibility is essential for the normal system operation to meet the dynamically varying demand of the system. The conventional generation technologies are increasingly required to provide more cyclic operation with faster ramping and frequent start-ups. Therefore, the generation planning exercise has decided the firm capacity mix in each year to facilitate the necessary flexibility requirements.

It should be noted that operational studies pertaining to long term planning have been conducted at minimum resolution of hourly timestep. Hence, the exact additional interventions required to operate the power system in shorter timespans preserving system stability are required to be assessed separately. These studies include analysis on dynamic transient studies and EMT modelling of power projects. Therefore, the associated cost of these additional interventions has not been considered.

7.12 Assessment of Environmental Implications

The environmental effects of each thermal options are considered in the initial selection of a candidate power plant in the planning process. All thermal power plants are required to adhere to the approved 'National Environmental (Ambient Air Quality) Regulations published in 2008 and the National Environmental (Stationary Sources Emission Control) Regulations published in 2019. Any additional costs to comply with the environmental regulations are considered in the capital cost of the respective power project. During project preconstruction phase, a detailed EIA shall be conducted to address and explore methods to mitigate all localised adverse environmental impacts.

The greenhouse gas emissions that impact the global environment is assessed for each planning scenario as presented in the Chapter 11. The GHG emission levels are analysed to ensure that the climate obligations of Sri Lanka to the UNFCC under the Nationally Determined Commitments (NDCs) are complied as well as to explore further opportunities to reduce greenhouse gas emissions.

7.13 Assessment of Implementation Time and Financial Scheduling

The implementation and financing of the planned power projects are two important aspects in planning and developing an electricity supply system. In fact, the total period of implementation of a project including feasibility studies varies depending on the type, technology and the location of the power project. Typical duration required for generation projects, including the period taken for preplanning activities, is shown below.

a)	Internal Combustion Engine	4 years
b)	Gas Turbine	4 years
c)	Combined Cycle Power Plant	6 years
d)	Coal Power Plant	7- 8 years
e)	Nuclear Power Plant	12- 15 years
f)	Hydropower Plant/Pumped Storage Power Plant	7 - 10 years
g)	Large scale solar park	4 – 6 years
h)	Large scale wind park	4 – 6 years
i)	Battery Energy Storage Systems	3 - 5 years

Developing the electricity generation system is often a highly capital intensive activity in the economy, hence funding and financing power sector projects remains as a critical challenge affecting the timely implementation of projects. An investment schedule of the Base Case scenario is presented to identify the necessary funding and financing requirement as well as for preparing future projections on electricity tariff system.

7.14 Study Parameters

The preparation of the plan is based on several parameters and constraints. These include technical and economical parameters and constraints which are to be used as input to Generation Planning Software. Parameters and constraints given in Grid Code were used in the studies and those are described in detail.

7.14.1 Study Period

Generation Expansion Panning studies are conducted for a period of 25 years (2025-2049) and the results of Base Case and all sensitivity studies are presented in the report for a period of 20 years (2025-2044). The consideration of additional years in the planning exercise is to enhance the accuracy of the solution to the optimization problem.

7.14.2 Economic Ground Rules

All analysis were performed based on economic (border) prices in terms of US dollars for investments and operations. All costs considered for the planning studies (in US dollars) are based on the costs available "on 1st January of the *current year* of the LTGEP" namely as at 1st of January 2024 as stipulated in the Generation Planning Code. As planning studies are conducted on USD exchange rate has minimal impact to the outcome of the planning studies. However, to express the results in terms of LKR the exchange rate of 326.7 LKR/USD (average value of December 2023 exchange rates) was used.

7.14.3 Plant Commissioning and Retirements

It is assumed that the power plants are commissioned or retired at the beginning of each year. However, in actual terms, CEB owned power plants are expected to be retired considering their remaining operable hours and actual implementation progress of new power projects. IPP power plants are to be retired according to the expiry dates of Power Purchase Agreements.

7.14.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as 0.880 USD/kWh (in 2024 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5 USD/kWh in 2011.

7.14.5 Reliability Criteria

As per the provisions stipulated in Sri Lanka Electricity Act Section 43(8) and Clause 15 of The General Policy Guidelines on the Electricity Industry issued on 2021, the PUCSL has to publish the reliability criteria for electricity network in consultation with the relevant licensees. "The technical and reliability requirements of electricity network of Sri Lanka" was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL [25].

a) Reserve Margin

Reserve margin is the measure of firm generation capacity available over and above the amount required to meet the system load requirements. When preparing the LTGEP, reserve margin values are maintained between 2.5% (minimum) and 20% (maximum) as published in Gazette

Extraordinary No. 2109/28 dated 2019-02-08. The Reserve Margin level is maintained between stipulated limits and necessary reserve margins, in each year, is maintained considering factors such as largest unit sizes, optimum usage of earmarked lands and stability of the network.

For calculation of reserve margin, firm capacity contributions from renewable energy sources were derived based on the resource profiles generated for the planning exercise. The firm capacity value was taken as the guaranteed capacity contribution during the critical periods. The period of interests are day peak and night peak of dry, high wind and wet seasons. The summary of the analysis conducted to derive the firm capacity contributions from renewable energy and storage sources are shown in Table 7.1.

The effect of geographical scattering shall be captured with production cost modelling with stochastic generation of renewable energy profiles. Furthermore, all storage devices are expected to have the capability to store energy from the grid, rather than from a single generating source. This contributes to obtaining higher firm capacity. The actual firm capacity shall vary year by year based on the characteristic of generation sources available each year and is to be captured through production cost modelling study.

Table 7.1-Summary of Firm Capacity Contributions from ORE and Storage

Technology	Dry		High Wind		Wet	
	Day Peak	Night Peak	Day Peak	Night Peak	Day Peak	Night Peak
Solar	0.54	0.00	0.50	0.00	0.37	0.00
Wind	0.01	0.06	0.16	0.35	0.01	0.08
Mini Hydro	0.08	0.08	0.26	0.26	0.38	0.38
Biomass	0.10	0.10	0.10	0.10	0.10	0.10
Battery Energy Storage	0.8	0.8	1.00	1.00	0.8	0.6
Pumped Hydro Storage	0.8	0.8	1.00	1.00	0.8	0.6

b) Loss of Load Probability (LOLP)

LOLP is another reliability index that indicates the probability that some portion of the load will not be satisfied by the available generation capacity. It is defined as the percentage of time during the system load exceeds the available generation capacity in the system.

The association between Reserve Margin and LOLP indices are interrelated and the exact values depend on the approach and the complexity of the adopted methodology. The LTGEP 2025-2044 is prepared maintaining the LOLP values within the stipulated maximum limit of 1.5% as stipulated in the Grid Code and published in Gazette Extraordinary No. 2109/28 dated 2019-02-08.

Transmission License shall prepare the Plan maintaining LOLP values at optimum levels with the mandate on flexibility to adjust the values providing sufficient justification, considering the aforementioned restrictions.

7.14.6 Discount Rate

The discount rate is used in order to analyse the economic costs and benefits at different times. The discount rate accounts several factors such as time value of money, earning power, budget constraints, purchasing power, borrowing limitations and utility of the money. Considering these facts, 10% discount rate was used for planning studies. Sensitivity to the discount rate is analysed by applying lower and higher discount rates.

7.14.7 Plant Capital Cost Distribution among Construction Years

The distribution of plant capital cost during the construction period is carried out by adopting "S" curve function relating expenditure to time based on 10% discount rate. The resultant annual investment requirement for individual power plants are given in the Investment Plan shown in Annex 12.1 and Annex 12.2 and discussed in Chapter 12.

7.14.8 Assumptions and Constraints Applied

The following were the assumptions and constraints that were applied to all studied cases.

a) All costs are based on economic prices for investment on generating plants. Furthermore, thermal plants will be dispatched in strict merit order, resulting in the lowest operating cost.

b) The planning process considers the cost to the economy in broader terms. Hence the financial cost associated with taxation, cost of capital, etc. are not considered.

c) All fuel prices assumed to remain constant as of the reference date, and expressed in economic terms (border prices) as stipulated in the Grid code.

d) All generating plants performance degradation throughout its lifetime has not been considered and accounted for during the studies.

e) Net generation values were used in planning studies instead of gross values.

f) The integration capacity of biomass and mini hydro power plants is not limited but could be considered on project by project basis depending on the feasibility.

g) All large-scale solar parks have been modelled based on PV plants with single axis tracking.

h) At least 90% of grid connected solar PV power plants and all wind power plants are required to have capabilities to curtail the generation, when necessary, as instructed by National System Control Centre.

i) The development of required LNG infrastructure will be available by the mid of 2027 for importing natural gas

j) Committed Power Plants are shown in the Table 7.2 below.

Table 7.2-Committed Power Plants

Power Plant	Capacity (MW)	Year of Operation
Hydro		
Moragolla Hydropower Plant	30.2	2024
Solar		
Grid connected solar	50 120	2025 2026
Wind		
Tendered and FIT projects	10 90	2025 2026
Thermal		
Natural Gas Combined Cycle Power Plant I (Sobadhanavi Ltd)	350	2024 – Open Cycle 2025 – Combined Cycle
Natural Gas Combined Cycle Power Plant II	350	2026 – Open Cycle 2027 – Combined Cycle
IC Engine power Plant Kerawalapitiya	200	2028
Kelanithissa Gas Turbines	130	2030

k) The Candidate Power Plants with earliest possible commissioning year are depicted in the Table 7.3 below.

Table 7.3-Candidate Power Plants

Power Plant	Capacity (MW)	Earliest Year of Operation
Thermal		
IC Engines (Diesel / FO / NG)	50/100/200	2028
Gas Turbine (NG)	50 /100 /200/300	2028
Combined Cycle Power Plant (NG)	300 / 400/500	2030
Coal Plant (High Efficient /Supercritical)	300 / 600	2030
Nuclear Power Plant	600	2040
Thermal –Operated with Hydrogen Blended NG		
IC Engines	100/200	2035
Gas Turbine	100 /200/300	2035
Combined Cycle Power Plant	300 / 400/500	2035
Thermal – Including CCS		
Combined Cycle Power Plant	300 / 400/500	2035
Storage		
Battery Energy Storage System		2026
Pumped Storage Power Plant	3 x 200 / 2 x 350	2032
Renewable		
Solar		2026
Wind		2026
Mini Hydro		2026
Biomass		2026

l) The spinning reserve requirement of 5% of the electricity demand at given instance is used. Additionally Dynamic Probabilistic Reserve requirements have been imposed within the software module to capture the variations of renewable energy resources.

m) For long term planning studies, a maximum allowable limit of 75% of System Non-Synchronous Penetration from electricity demand has been considered during this planning horizon.

n) The maximum generation of a single generation unit or interconnection is limited to 25% of electricity demand at a given instance to ensure safe operation of the power system.

o) Retirement of BESS after 10 years is considered in the planning horizon and the retired capacities are replaced with similar capacity new BESS.

p) Retirement of existing ORE power plants are modelled based on the expiry of their PPA and is modelled with replacement with similar capacity new power plant of the same technology.

q) Plant retirements of CEB owned plants and IPP plants are given in Table 7.4. The power plant retirements are assumed to be at the beginning of each year. However, the actual retirement of CEB owned power plants are to be made after further evaluating the actual plant condition at the time of retirement (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

Table 7.4-Plant Retirement Schedule

CEB Power Plant Retirement	**Year**	**IPP Power Plants' PPA expiry**	**Year**
Kelanithissa Frame5 GTs [1]	2025	Westcoast Combined Cycle plant	2035
Barge mounted power plant	2031		
Sapugaskanda PS A (4 units)	2031		
Sapugaskanda PS B (8 Units)	2031		
Kelanithissa GT7 [2]	2026		
Kelanithissa Combined Cycle plant I & II	2033		
Uthuru Janani power plant	2033		
Lakvijaya coal plant unit I	2041		
Lakvijaya coal plant unit II & III	2044		

[1] It should be noted that Small GTs in Kelnatissa (KPS Frame 5 GTs) are considered to be retired by 2025, however two units of the power plant is expected to be retained in the system for Colombo power restoration after total or partial blackout situation, until a suitable power plant/BESS which provide such service is added to the system

[2] Upon retirement of GT7 in 2026, the possibility of retrofitting the asset as a synchronous condenser shall be evaluated.

CHAPTER 8
SCENARIO ANALYSIS

8.1 Background

This chapter presents the analysis of the different scenarios considered in the generation expansion planning studies in determination of the Base Case and the Reference case. All scenarios were developed for the demand forecast as described in Table 3.3.

The current policy for the sector is stipulated through General Policy Guidelines in Respect of The Electricity Industry as issued in January 2022 which was considered during the preparation of the Base Case Plan. Nevertheless, planning studies were conducted under several generation expansion scenarios to analyse pathways to achieve carbon neutrality and to evaluate the technical and economic implications of complying with the policy guideline. In addition to the above policy directives, as per the “The technical and reliability requirements of electricity network of Sri Lanka” which was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL, the scenarios were developed to maintain reserve capacity that could be served on demand, within the stipulated limits of 2.5% to 20% over the peak demand throughout the planning horizon.

Section 8.2 describes the scenarios analysed within the stipulated policy guidelines in order to achieve 70% renewable energy by 2030 and in view of achieving carbon neutrality beyond the planning horizon by means such as increasing renewable energy share over 70%, cross border interconnection with India and adopting nuclear power technology. Section 8.3 describes the scenarios analysed in order to determine the least cost scenario in a policy unconstrained environment. Sensitivity on fuel price, capital cost and externality cost for these scenarios is discussed in section 8.4 and a comparison provided in section 8.5.

8.2 Policy Constrained Scenarios

Policy constrained scenarios were developed in order to derive the Base Case 2025-2044. When developing the Base Case Plan, special consideration was given to the "General Policy Guidelines for the Electricity Industry'' as stipulated in the Section 5 of Sri Lanka Electricity Act no 20 of 2009 (as amended) and in the Section 30 of the Public Utilities Commission of Sri Lanka (PUCSL) Act no 35 of 2002. This policy guideline was approved by the Cabinet of Ministers in November 2021 and issued by the Ministry of Power in January 2022. The evaluated scenarios are as follows.

Major hydro, solar, wind, mini hydro and biomass were considered as contributing to achieve renewable energy share. In order to maintain the 70% renewable energy from 2030 onwards battery energy storage and pumped storage power plants (Maha with 3 x 200 MW capacity and Wewathenna with 2 x 350 MW capacity) are considered. Additionally, natural gas based IC engine, gas turbine and combined cycle power plants are potential candidates. With the goal of carbon neutrality, hydrogen blended natural gas power plants and nuclear power plants are considered viable options beyond 2035. Considering the importance of regional integration, interconnection with India was also considered.

8.2.1 Scenario 1
Maintain 70% RE from 2030 onwards, with 500 MW HVDC interconnection, no coal capacity additions

This scenario was developed to achieve 70% of electricity from renewable sources by 2030 and onwards. Interconnection with India was considered in this scenario. As per the latest studies, an asynchronous interconnection between the Indian and Sri Lankan electricity grids through a 2x500MW HVDC link from Madurai New (India) to Mannar (Sri Lanka) has been considered. At phase-1, 500 MW HVDC is considered. Considering the numerous cross border electricity trade options discussed in Chapter 6, 250 MW is considered to be from Round the Clock (RTC) and 250 MW from Indian Day Ahead Market (DAM). A landed cost at India HVDC terminal around 4.68 UScts/kWh was considered for the RTC contracts and hourly prices as per Table 6.1 in Chapter 6, were considered for the DAM. The limitation of maximum power flow of less than 25% of the electricity demand in Sri Lanka for every instance is imposed on the interconnection.

The total present value cost of this scenario is USD 15,109 million. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.1.

Table 8.1 - Capacity Additions by Plant Type : Scenario 1

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	
					(MW)	(%)
Renewables	2,735	2,600	2,530	2,850	10,715	64
Gas Turbine	-	330	800	1,300	2,430	15
IC Engine	200	-	200	200	600	4
Combined Cycle	465	-	-	400	865	5
Nuclear	-	-	-	-	-	-
Pumped Storage	-	600	-	-	600	4
Battery Storage	305	450	100	50	905	5
HVDC	-	-	500	-	500	3
Total	**3,705**	**3,980**	**4,130**	**4,800**	**16,615**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.2.2 Scenario 2
Maintain 70% RE from 2030 onwards, without HVDC interconnection, no coal capacity additions

This scenario was developed to achieve 70% of electricity from renewable sources by 2030 and onwards. HVDC interconnection was not considered in developing this scenario. The development of second pumped hydro storage is a requirement to maintain the 70% renewable energy share during the planning horizon. Renewable energy and battery energy storage capacities are also further increased in order to maintain 70% RE share beyond year 2030.

The total present value cost of this scenario is USD 15,269 million. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.2.

Table 8.2 - Capacity Additions by Plant Type : Scenario 2

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	(%)
Renewables	2,735	2,600	2,530	3,850	11,715	65
Gas Turbine	-	330	800	1,100	2,230	12
IC Engine	200	-	200	200	600	3
Combined Cycle	465	-	-	400	865	5
Nuclear	-	-	-	-	-	-
Pumped Storage	-	600	350	350	1,300	7
Battery Storage	305	450	150	300	1,205	7
HVDC	-	-	-	-	-	-
Total	**3,705**	**3,980**	**4,030**	**6,200**	**17,915**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.2.3 Scenario 3
Maintain 70% RE from 2030 onwards, With 500 MW HVDC interconnection, with nuclear Power, No coal capacity additions

This scenario was developed to achieve 70% of electricity from renewable sources by 2030 and onwards. Additionally, nuclear power development was considered as a potential candidate option beyond 2035, in view of achieving carbon neutrality in power generation in 2050. Nuclear power is the second-largest source of low-carbon electricity today and it is regarded as one of the technologies having large potential to combat climate change. Despite the declining investment on nuclear power on advanced countries, several new comer countries are exploring the possibility of introducing nuclear power mainly driven by energy security concerns.

Nuclear power development was analysed in a scenario containing the development of 500 MW cross-border interconnection with India and the planned energy storage additions including 600 MW pumped storage power plant. It is evident that with the retirement of all existing coal power units in 2044, the need for affordable base load power necessitates the selection of a 600 MW (552 MW net) nuclear power plant for base load operations. However, the relatively large unit size of NPP continues to be the biggest technical challenge for the Sri Lankan system and the potential of small-scale modular reactor nuclear power plants (SMRs) should also be evaluated, considering their commercial viability at the time. The HVDC interconnection and PSPP become a prerequisite to integrate a large nuclear power unit to the system assuming the terms of operation of the interconnection are set in favour of the NPP operation. Accordingly, during the off-peak duration which becomes critical for the nuclear power operation, both exporting and storage are undertaken to avoid de-loading of the nuclear power plant.

The total present value cost of this scenario is USD 15,090 million which is USD 19 million lower than a similar case without considering the nuclear power (scenario 1). Although the investment cost is higher in Scenario 3 compared to Scenario 1, the operational cost savings from nuclear power make this scenario much more cost-effective overall. Capacity additions by plant type which are summarized in five-year periods are shown in Table 8.3.

Table 8.3 - Capacity Additions by Plant Type : Scenario 3

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	Total Capacity Addition (%)
Renewables	2,735	2,600	2,530	2,850	10,715	64
Gas Turbine	-	330	800	1200	2,330	14
IC Engine	200	-	200	200	600	4
Combined Cycle	465	-	-	-	465	3
Nuclear	-	-	-	600	600	4
Pumped Storage	-	600	-	-	600	4
Battery Storage	305	450	100	50	905	5
HVDC	-	-	500	-	500	3
Total	**3,705**	**3,980**	**4,130**	**4,900**	**16,715**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.2.4 Scenario 4
Achieve 70% RE by 2030 and increase to 80% by 2044, with 1000 MW HVDC interconnection, no coal capacity additions

This scenario was developed to achieve 70% of electricity from renewable sources by 2030 and further increase the renewable energy share during the planning horizon to reach 80% by 2044. In support of achieving 80% renewable energy the second pumped storage site has to be developed. Furthermore phase 2 of the HVDC interconnection is also considered when developing this scenario. Renewable energy and battery energy storage capacities are also increased in order to achieve 80% RE share.

The total present value cost of this scenario is USD 15,301 million. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.4.

Table 8.4 - Capacity Additions by Plant Type : Scenario 4

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	Total Capacity Addition (%)
Renewables	2,735	2,600	2,530	3,850	11,715	65
Gas Turbine	-	330	600	800	1,730	10
IC Engine	200	-	200	200	600	3
Combined Cycle	465	-	-	-	465	3
Nuclear	-	-	-	-	-	-
Pumped Storage	-	600	350	350	1,300	7
Battery Storage	305	450	-	500	1,255	7
HVDC	-	-	500	500	1,000	6
Total	**3,705**	**3,980**	**4,180**	**6,200**	**18,065**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.2.5 Scenario 5

Achieve 70% RE by 2030, increase to 80% from 2040 onwards, with aggressive solar and BESS development, with 500 MW HVDC interconnection, no coal capacity additions

This scenario was developed to achieve 70% of electricity from renewable sources by 2030 with due consideration given to aggressive solar and BESS development. By progressing with an aggressive development of solar and battery energy storage the renewable energy share could be reached to 80% as sooner as 2040 in this scenario. The energy shifting requirement requires BESS of both 4 hour and 8 hour duration. However, total present value cost of this scenario is USD 17,009 million which is the highest cost scenario among the policy constrained scenarios. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.5.

Table 8.5 - Capacity Additions by Plant Type : Scenario 5

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	Total Capacity Addition (%)
Renewables	3,485	3,350	3,280	3,600	13,715	70
Gas Turbine	-	130	500	500	1,130	6
IC Engine	200	-	200	200	600	3
Combined Cycle	465	-	-	-	465	2
Nuclear	-	-	-	600	600	3
Pumped Storage	-	600	-	-	600	3
Battery Storage	305	650	400	750	2,105	11
HVDC	-	-	500	-	500	3
Total	**4,455**	**4,730**	**4,880**	**5,650**	**19,715**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.2.6 Selection of the Base Case Scenario

A summary of the investment and operation cost of the policy constrained scenarios is given in Table 8.6.

Table 8.6 – Cost Comparison of Policy Constrained Scenarios

	PV Cost of Investment (MUSD)	PV Cost of Operation (MUSD)	Total PV Cost (MUSD)
Scenario 1	9,109	6,000	15,109
Scenario 2	9,195	6,074	15,269
Scenario 3	9,171	5,918	15,090
Scenario 4	9,640	5,661	15,301
Scenario 5	11,570	5,438	17,009

Out of the five policy constrained scenarios, scenario 3 has the lowest total present value cost while scenario 5 has the highest. Investment cost of the scenarios 4 & 5 reaching 80% RE share are significantly higher and hence contributing to the higher total present value cost. However, the operation cost of scenario 5 is lowest due to high RE share.

After evaluation of all policy constrained scenarios described above, scenario 3 was selected as Base Case 2025-2044 as it indicated the lowest total present value cost of USD 15,090 million among the five policy constrained scenarios and was technically feasible. The present value cost difference of scenario 1 and 3 is only USD 19 million due to the selection of nuclear power option against combined cycle power plant operated on blended fuel of natural gas and hydrogen. Annual capacity additions of scenario 3, base case, is given in Chapter 10 with detailed analysis and annual capacity additions of other scenarios are given in Annex 8.

8.3 Policy Unconstrained Scenarios

Policy unconstrained scenarios were developed in order to derive the Reference Case 2025-2044. To develop the reference case 2025-2044, the Draft Generation Planning Code in the Draft Grid Code [24] issued by the Transmission Licensee was used as a guideline. As per the grid code, the reference case should be developed with exclusion of any policy guidelines on generation technology options that would cause the plan to deviate from least cost. In addition, candidate non-dispatchable power plants required to be included owing to policy guidelines issued by the commission or any of the Transmission Licensee's own policies, are not included in the reference case, unless the Transmission Licensee can demonstrate that such power plant costs shall not violate the least-cost objective of developing the reference case.

Accordingly, as the first step of developing the reference case, a case with ORE power plants already in operation as at 1st January 2023 and the committed renewable energy plants was considered. When the case was analysed, it was observed that further cost reductions could be expected by incorporating candidate ORE additions to the plan to a certain extent. Several scenarios were evaluated with varying candidate ORE additions throughout the planning horizon which do not require substantial investments in network or operational reinforcements. The evaluated scenarios are as follows.

8.3.1 Scenario 6
Maintain 65% RE from 2028 onwards, with coal capacity additions

This scenario was developed considering achievement of 65% renewable share by 2028 and beyond. Coal power development is considered as a candidate throughout the planning horizon. The requirement of battery energy storage is limited due to having adequate firm power resources and minimal curtailments. The development of PSPP is required for optimal operation of generation units. The total present value cost of this scenario is USD 14,328 million. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.7.

Table 8.7 - Capacity Additions by Plant Type : Scenario 6

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition	
					(MW)	(%)
Renewables	2,135	1,950	2,030	2,750	8,865	60
Gas Turbine	-	1130	700	1000	2,830	19
IC Engine	200	-	200	-	400	3
Combined Cycle	465	-	-	-	465	3
Nuclear	-	-	-	-	-	-
Coal	-	-	300	900	1,200	8
Pumped Storage	-	200	400	-	600	4
Battery Storage	105	50	-	150	305	2
HVDC	-	-	-	-	-	-
Total	**2,905**	**3,330**	**3,630**	**4,800**	**14,665**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.3.2 Scenario 7
Maintain 60% RE from 2027 onwards, with coal capacity additions

This scenario was developed considering achievement of 60% renewable share by 2027 and beyond. Coal power development is considered throughout the planning horizon. The requirement of battery energy storage is further limited due to having adequate firm power resources and minimal curtailments. The total present value cost of this scenario is USD 14,244 million. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.8.

Table 8.8 - Capacity Additions by Plant Type : Scenario 7

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition	
					(MW)	(%)
Renewables	1,775	1,520	1,705	2,325	7,325	55
Gas Turbine	-	1,430	900	500	2,830	21
IC Engine	200	-	200	-	400	3
Combined Cycle	465	-	-	-	465	4
Nuclear	-	-	-	-	-	-
Coal	-	-	300	1,200	1,500	11
Pumped Storage	-	-	-	600	600	5
Battery Storage	105	50	-	-	155	1
HVDC	-	-	-	-	-	-
Total	**2,545**	**3,000**	**3,105**	**4,625**	**13,275**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.3.3 Scenario 8
Maintain 60% RE from 2027 onwards, no coal capacity additions

This scenario is developed similar to scenario 7 but without considering coal power development. The total present value cost of this scenario is USD 14,369 million. Additional combined cycle power plant development is foreseen in the scenario with the retirement of coal power plants. The capacity additions by plant type which are summarized in five-year periods are shown in Table 8.9.

Table 8.9 - Capacity Additions by Plant Type : Scenario 8

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	(%)
Renewables	1,775	1,520	1,705	2,325	7,325	56
Gas Turbine	-	1,430	900	200	2,530	19
IC Engine	200	-	200	-	400	3
Combined Cycle	465	-	300	1,200	1,965	15
Nuclear	-	-	-	-	-	-
Coal	-	-	-	-	-	-
Pumped Storage	-	-	-	600	600	5
Battery Storage	105	50	-	-	155	1
HVDC	-	-	-	-	-	-
Total	**2,545**	**3,000**	**3,105**	**4,325**	**12,975**	**100**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

8.3.4 Selection of the Reference Case Scenario

A summary of the investment and operation cost of the policy unconstrained scenarios is given in Table 8.10.

Table 8.10 - Cost Comparison of Policy Unconstrained Scenarios

	PV Cost of Investment (MUSD)	PV Cost of Operation (MUSD)	Total PV Cost (MUSD)
Scenario 6	7,513	6,815	14,328
Scenario 7	6,462	7,782	14,244
Scenario 8	6,351	8,017	14,369

All the above scenarios indicated lower present value costs than the existing policy-based scenarios. Scenario 7 which achieved 60% RE by 2027, maintained 60% RE beyond 2027 and with coal fired power plants indicated the lowest present value cost of USD 14,244 million among the three policy unconstrained scenarios.

Therefore, scenario 7 was identified as the Reference Case of LTGEP 2025-2044 as it indicated the lowest present value cost unconstrained by policy guidelines and operationally feasible. Approximately USD 846 million cost increment could be observed as the policy cost of incorporating 70% Renewable energy share by 2030 with no future coal power plant additions.

Annual capacity additions of scenario 7, reference case, is given in Chapter 9 with detailed analysis and annual capacity additions of other scenarios are given in Annex 8.

8.4 Scenario Sensitivities

8.4.1 Impact of Fuel Price Sensitivity

Historical fuel price variations show that high volatility in global LNG prices and relatively low level of volatility in international coal prices. However, due to global economic crisis coal prices have soared drastically during the year 2022. Considering both the extent of volatility and the likelihood of volatility of all the fuel prices, it is important to examine the potential impact on scenarios.

The long term planning studies considers the constant fuel prices throughout the planning horizon and the impact of the fuel price volatility and variation is separately investigated as a sensitivity analysis in the planning process. The impact of long term global fuel price escalations and short term fuel price volatility are important considerations in terms of electricity system security. Table 8.11 summarizes the cost of each fuel types considered for the planning horizon of scenarios pertaining to varying renewable energy shares.

Table 8.11 - Fuel Price Projections for Fuel Price Sensitivities

Fuel Price Sensitivity	Coal (USD/ Mton)	LNG (USD/ MMBtu)	Diesel (USD/bbl)	Furnace Oil (USD/bbl)	Naptha (USD/bbl)	Nuclear Fuel (USD/kg)
Base Based on World Bank Forecast (October ,2023)	133	11	112	117	86	1,832
High Based on actual fuel prices (2022 Average)	305	13	151	155	103	1,873
Low Based on actual fuel prices (2020 Average)	90	6	64	70	49	1,616

Variation in the fuel prices was applied to key scenarios to assess the degree of impact on the operation cost of each scenario. The results provide an indication of the robustness of each scenario against fuel price variations as presented in Table 8.12.

Table 8.12 - Present Value of costs of Scenarios for Fuel Price Sensitivities

	Base Fuel Price	High Fuel Price		Low Fuel Price	
	Total PV Cost (MUSD)	Total PV Cost (MUSD)	Difference with Base Fuel Prices (MUSD)	Total PV Cost (MUSD)	Difference with Base Fuel Prices (MUSD)
Scenario 3 (Base Case)	15,090	18,446	+3,356	13,075	-2,015
Scenario 5 (80% RE)	17,009	20,090	+3,081	15,242	-1,767
Scenario 7 (Reference)	14,244	18,649	+4,405	11,453	-2,791

According to the results, Scenario 5 targeting 80% share of renewable energy from 2040 has reduced import dependence through the development of local renewable resources and shows greater resilience against fuel price increases. However, this scenario remains as the most expensive scenario from all considered fuel price sensitivity scenarios. The primary reason for this substantial cost lies in the investment requirement associated with the aggressive renewable development in scenario 5. Furthermore, under an extreme hike in fuel price, scenario 3 (Base Case) which is targeting a 70% renewable energy share beyond 2030 emerges as the most cost-effective option. However, the likelihood of having such aggressive fuel prices throughout the whole 20 year planning horizon is very low.

The increased reliance on the natural gas based capacities in all scenarios can lead to higher impact of gas prices fluctuations. It is important to adopt available measures to minimize the risk of imported natural gas price fluctuations. In the event where the local natural gas is available in future, country will have the opportunity to lower the dependency on imported liquid natural gas.

8.4.2 Impact of Cost Projection Sensitivity

The long term planning studies have been conducted considering constant capital and operating costs throughout the planning horizon. The importance of considering the capital cost projections in conjunction with operational cost reduction projections is necessary to evaluate the robustness of planning scenarios.

The capital cost reduction during the past decade of solar PV and wind has been considerable and is expected to decline further in the next decade. As many countries gear up for higher renewable shares, the accelerated requirement of battery storage systems is also expected to bring down their costs. Therefore, it is necessary to consider projections for capital cost reduction in long term studies, to evaluate the robustness of selecting an optimum planning scenario.

The cost projection for renewable energy, thermal and storage technologies and fuel prices have been derived based on the forecasts given in the World Energy Outlook 2023 published by International Energy Agency (IEA) and depicted in Figure 8.1 and Figure 8.2 respectively.

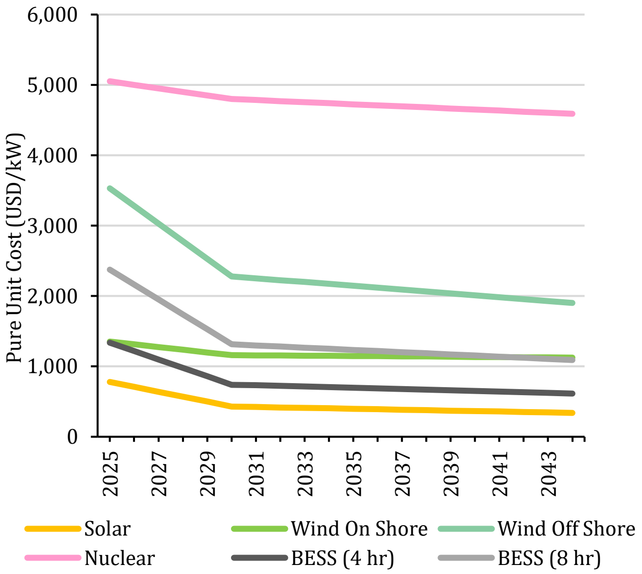


Figure 8.1 - Technology Cost Projections

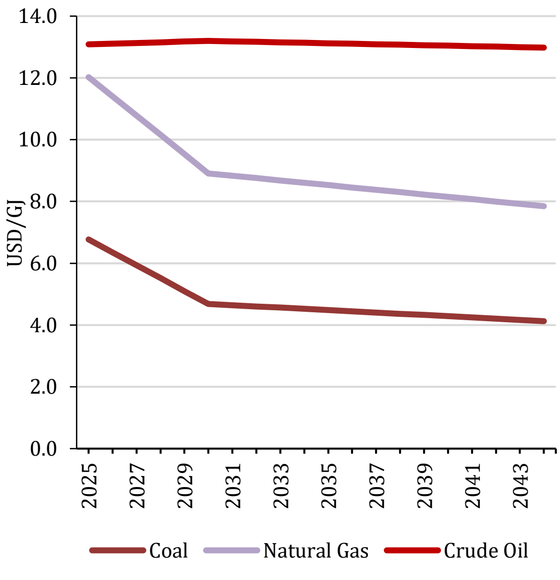


Figure 8.2 - Fuel Price Projections

The present value cost of the key scenarios are presented in Table 8.13.

Table 8.13 - Sensitivity of Cost Projections for Key Scenarios

Scenario	PV Cost of Investment (MUSD)	PV Cost of Operation (MUSD)	Total PV Cost (MUSD)
Scenario 3 (Base Case)	7,619	5,691	13,310
Scenario 5 (80% RE)	8,695	5,305	14,000
Scenario 7 (Reference)	5,788	7,235	13,023

As per the results, it is observed that even with cost projections, Scenario 7 (considering 60% share in renewable resources by 2030), is showing the lowest total cost. Scenario 5 targeting 80% renewable share by 2040 onwards is the most expensive with total present value cost difference of 977 million USD compared to Scenario 7 (Reference case).

8.4.3 Impact of SNSP Limit Variation

Variation of maximum SNSP limits will have an impact on the system operation as well as system stability. Therefore, it is important to consider the impact on both operational cost and additional investment cost required on system enhancements. Although it is possible to evaluate the changes to operational cost through long term planning studies, the exact investment requirement on the intervening technologies requires further detailed studies carried out on smaller time steps.

Table 8.14 depicts the variations of present value cost of key scenarios under higher SNSP values for comparison. However, it is to be noted that these results require to further consider additional costs required on investment for higher SNSP levels.

Table 8.14 - Sensitivity of Scenarios Considering the SNSP Limits

SNSP Limit	Scenario	PV Cost of Investment (MUSD)	PV Cost of Operation (MUSD)	Total PV Cost (MUSD)
75%	Scenario 3 (Base Case)	9,171	5,918	15,090
	Scenario 5 (80% RE)	11,570	5,438	17,009
100%	Scenario 3 (Base Case)	9,171[1]	5,657	14,828[1]
	Scenario 5 (80% RE)	11,570[1]	5,000	16,570[1]

[1]Investment cost is expected to increase with additional interventions.

8.4.4 Impact of Externality Cost

Estimating externality costs of specific power generating technologies and fuel options is a challenging task due to the difficulty in isolating the contribution of power industry from the impacts from all other industries. Furthermore, electricity accounts only about 14% share of the total energy usage in the country. Literature suggest that monetizing the externalities is highly subjective and could vary within a wide range depending on the income level of the country, population density around the power plants etc. Therefore, a country specific study needs to be conducted to evaluate the externality cost applicable to Sri Lanka. Furthermore, externality cost should be estimated for both thermal and renewable power generation on a same basis to be comparable.

In the event, a country specific study is not available, the report “Environmental Externalities from Electric Power Generation, The Case of Regional Center for Renewable Energy and Energy Efficiency (RCREEE) Member States, September 2013” is used as a source for externality cost for conducting sensitivity analysis in LTGEP 2025-2044. The report has summarized the range of externalities estimation from previous studies for most of the fuel options and renewables. Accordingly the mean externality cost was used for analysis as indicated in Figure 8.3.

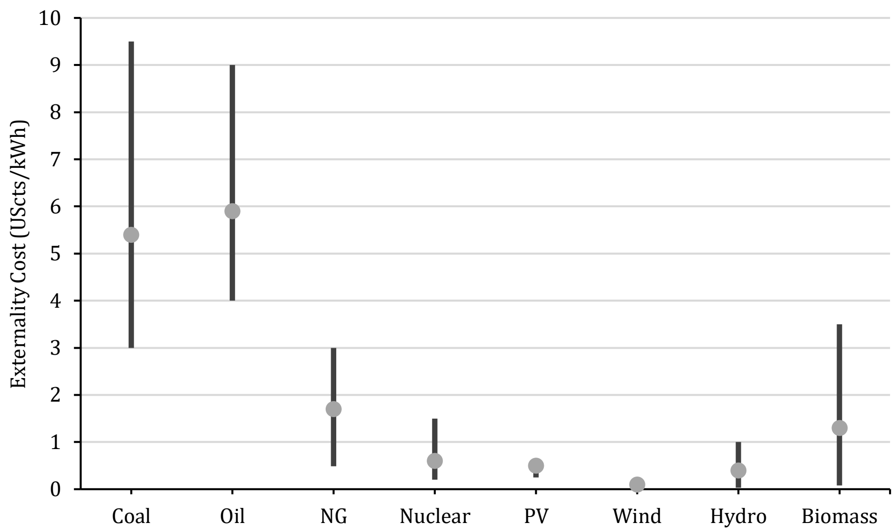


Figure 8.3 - Range of Externality Cost of Generation Technologies

After consideration of the environmental externality cost, the present value cost of key scenarios are as given in Table 8.15.

Table 8.15 - Sensitivity of Scenarios Considering the Externality Cost

Scenario	PV Cost of Investment (MUSD)	PV Cost of Operation (MUSD)	Total PV Cost (MUSD)
Scenario 3 (Base Case)	9,171	10,305	19,477
Scenario 5 (80% RE)	11,570	9,533	21,104
Scenario 7 (Reference)	6,462	13,009	19,471

It should be noted that even with the consideration of environmental externalities the scenario 7 (reference case) is the lowest cost scenario although the total cost difference with the scenario 3 (base case) is minimal.

8.5 Comparison of Future Energy Supply Alternatives

8.5.1 Summary of Scenarios

The Figure 8.4 and Figure 8.5 illustrates the projected energy mix and capacity mix in 2044 for all scenarios considered.

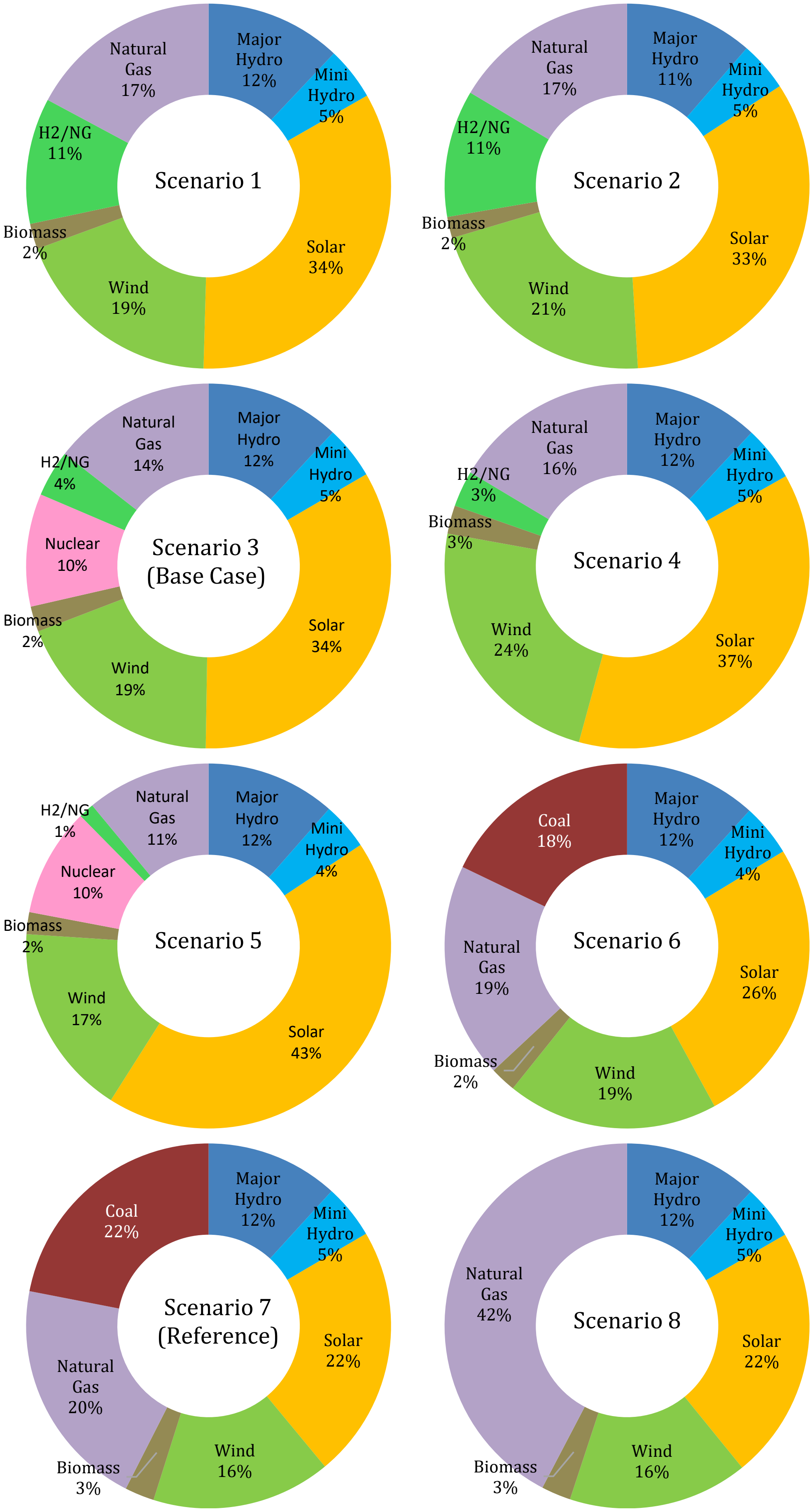


Figure 8.4 - Energy Share within Sri Lanka Comparison in 2044

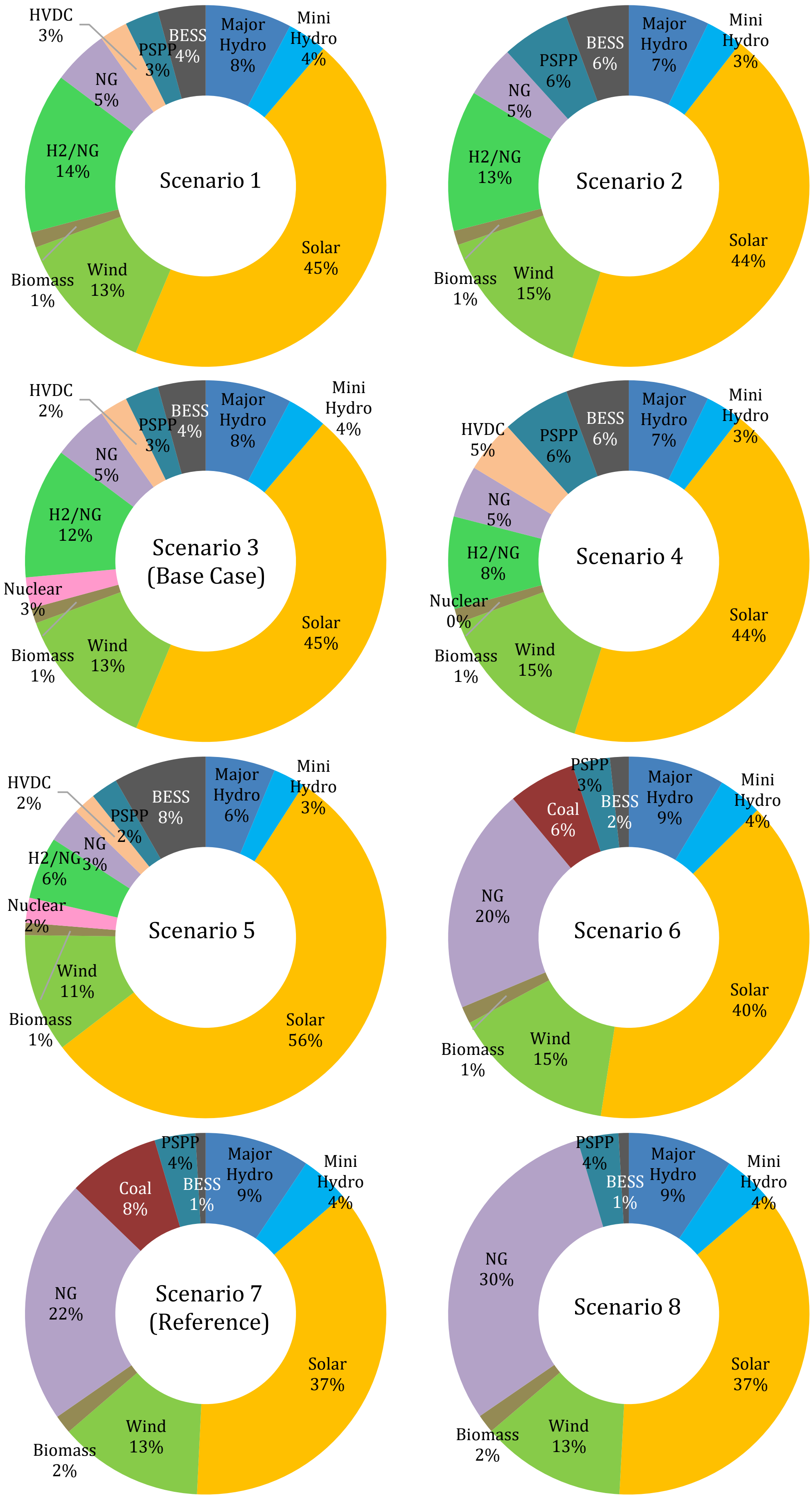


Figure 8.5 - Capacity Share Comparison in 2044

A comparison of capacity additions and present value costs of scenarios with the Base Case plan is shown in Table 8.16.

Table 8.16 - Summary of Present Value Cost of the Scenarios

Scenario	Capacity Additions between 2025-2044		Total Present Value Cost (MUSD)	Difference of PV Cost compared to Base Case (MUSD)
Scenario 1: Maintain 70% RE from 2030 onwards, With 500 MW HVDC interconnection No coal capacity additions	Renewables	10,715	15,109	19
	Natural Gas	3,895		
	Nuclear	-		
	Coal	-		
	Pumped Storage	600		
	Battery Storage	905		
	HVDC	500		
Scenario 2: Maintain 70% RE from 2030 onwards, Without HVDC interconnection No coal capacity additions	Renewables	11,715	15,269	180
	Natural Gas	3,695		
	Nuclear	-		
	Coal	-		
	Pumped Storage	1,300		
	Battery Storage	1,205		
	HVDC	-		
Scenario 3: Maintain 70% RE from 2030 onwards, With 500 MW HVDC interconnection, With Nuclear Power No coal capacity additions (Base Case)	Renewables	10,715	15,090	0
	Natural Gas	3,395		
	Nuclear	600		
	Coal	-		
	Pumped Storage	600		
	Battery Storage	905		
	HVDC	500		
Scenario 4: Achieve 70% RE by 2030 and increase to 80% by 2044 With 1000 MW HVDC interconnection No coal capacity additions	Renewables	11,715	15,301	211
	Natural Gas	2,795		
	Nuclear	-		
	Coal	-		
	Pumped Storage	1,300		
	Battery Storage	1,255		
	HVDC	1000		
Scenario 5: Achieve 70% RE by 2030, increase to 80% from 2040 onwards, With aggressive Solar and BESS development With 500 MW HVDC interconnection, No coal capacity additions	Renewables	13,715	17,009	1,919
	Natural Gas	2,195		
	Nuclear	600		
	Coal	-		
	Pumped Storage	600		
	Battery Storage	2,105		
	HVDC	500		

Scenario	Capacity Additions between 2025-2044		Total Present Value Cost (MUSD)	Difference of PV Cost compared to Base Case (MUSD)
Scenario 6: Maintain 65% RE from 2028 onwards, With coal capacity additions	Renewables	8,865	14,328	-762
	Natural Gas	3,695		
	Nuclear	-		
	Coal	1,200		
	Pumped Storage	600		
	Battery Storage	305		
	HVDC	-		
Scenario 7: Maintain 60% RE from 2027 onwards, With coal capacity additions (Reference Case)	Renewables	7,325	14,244	-846
	Natural Gas	3,695		
	Nuclear	-		
	Coal	1,500		
	Pumped Storage	600		
	Battery Storage	155		
	HVDC	-		
Scenario 8: Maintain 60% RE from 2027 onwards, No coal capacity additions	Renewables	7,325	14,369	-721
	Natural Gas	4,895		
	Nuclear	-		
	Coal	-		
	Pumped Storage	600		
	Battery Storage	155		
	HVDC	-		

The unit generation cost of a power system refers to the average cost of producing electricity across an entire power grid or system. This metric aggregates the costs of generating electricity from all the different power plants and energy sources that make up the power system, providing a comprehensive view of how much it costs to generate each unit of electricity within that system. A comparison of unit generation cost of the scenarios over the planning horizon is shown in Figure 8.6.

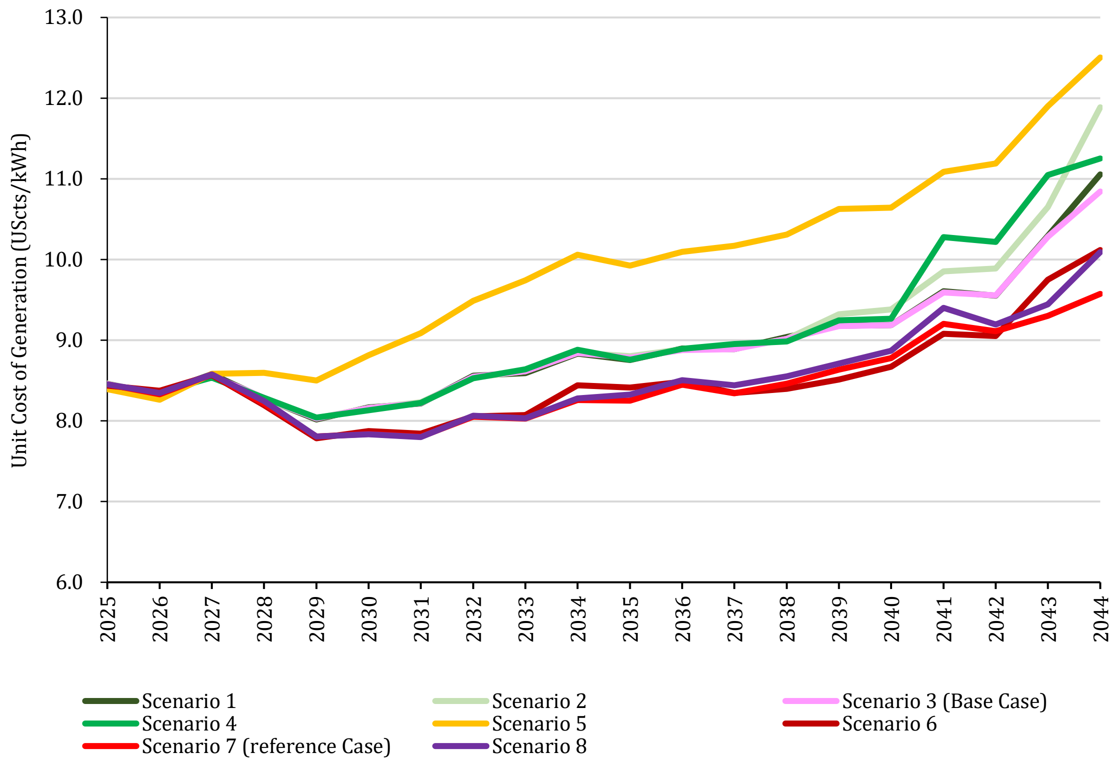


Figure 8.6 - Unit Cost of Generation of Scenarios

8.5.2 Global Context

Table 8.17 shows the present and projected energy mix in a number of different countries. It could be observed that majority of the countries are focusing on reducing coal power generation significantly from the generation mix with increased contribution from low carbon or zero carbon generation sources such as Natural Gas, Nuclear and Renewables. Another important observation is that most of the countries and regions are thriving to increase the renewable share significantly by projecting higher renewable shares.

Especially, European Union (EU) energy mix mainly consists of renewable energy since the power grid is interconnected among EU countries and hence the technical limitations of absorbing renewable energy are less. Renewable energy share is projected to be maintained at 84% in 2050.

Table 8.17 - Present & Projected Power Generation Mix in Other Countries and Regions

		Renewable	NG	Nuclear	Coal	Other
USA	2022	22%	39%	18%	20%	1%
	2050	80%	7%	12%	0%	0%
China	2022	30%	3%	5%	62%	0%
	2050	77%	2%	8%	13%	0%
EU	2022	39%	20%	22%	17%	3%
	2050	84%	2%	13%	0%	0%
Japan	2022	21%	34%	6%	31%	8%
	2050	61%	9%	19%	6%	6%
Russia	2022	18%	45%	19%	18%	1%
	2050	28%	43%	22%	7%	0%
India	2022	23%	2%	3%	72%	0%
	2050	73%	3%	6%	18%	0%
Middle East	2022	4%	72%	2%	0%	22%
	2050	35%	55%	3%	0%	6%
Asia Pacific	2022	27%	10%	5%	56%	1%
	2050	71%	6%	7%	15%	1%
Sri Lanka	**2022**	**52%**	**0%**	**0%**	**32%**	**15%**
	2044	**72%**	**18%**	**10%**	**0%**	**0%**

Source: IEA-World Energy Outlook 2023, Draft LTGEP 2025-2044

CHAPTER 9
REFERENCE CASE SCENARIO

9.1 Background

This chapter presents the results of the reference case for 2025-2044 planning horizon in detail which is presented as the scenario 7 in chapter 8. Capacity additions and system energy share of the reference scenario is presented along with cost comparison with base case. In addition, the comparison of CO_2 emissions due to the implementation of the reference case is presented in this chapter.

The Draft Generation Planning Code in the Draft Grid Code [24] issued by the Transmission Licensee was used as a guideline to develop the reference case. As per the grid code, the reference case should be developed with exclusion of any policy guidelines on generation technology options that would cause the plan to deviate from least cost.

Hence the reference case plan is the unconstrained least cost plan and the total cost of reference case demonstrates the total present value cost of generation expansion for the planning horizon unconstrained by policies. It indicates the least cost development pathway as well as provides a basis for comparison to other scenarios that are constrained by policies.

9.2 Reference Case Plan

The reference case plan is given in Table 9.1 and the total present value cost of the Reference Case Plan for the period 2025-2044 is USD 14,244 million based on the discount rate of 10%.

This scenario was developed considering achievement of 60% renewable share by 2027 and maintain the same share through the planning horizon. Due to the lower share of renewables the BESS requirement is minimized which reduces the investment cost considerably.

Furthermore, Coal power development is considered and next coal power plant addition is considered in year 2035.

Table 9.1 - Reference Case Scenario 2025-2044

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage**	150 MW **50 MW** **10 MW** 10 MW 10 MW **5 MW/10 MWh**	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	150 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 20 MW 50 MW 20 MW 20 MW	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 20 MW 50 MW 20 MW 20 MW		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	150 MW 20 MW 50 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa** Gas Turbine - Natural Gas	**130 MW** 200 MW
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	200 MW *(68) MW* *(72) MW* *(62) MW*
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas	200 MW
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	100 MW *(165) MW* *(163) MW* *(26.7) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas	2x300 MW
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 10 MW 10 MW	Coal Power Plant *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 75 MW 10 MW 10 MW	Gas Turbine - Natural Gas	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 75 MW 10 MW 10 MW	Gas Turbine - Natural Gas	300 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 100 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 100 MW 100 MW 10 MW	Gas Turbine - Natural Gas	300 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pumped Storage Power Plant (Maha)	150 MW 100 MW 100 MW 10 MW 200 MW	Gas Turbine - Natural Gas	100 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pumped Storage Power Plant (Maha)	150 MW 200 MW 100 MW 10 MW 200 MW	Coal Power Plant *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	300 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pumped Storage Power Plant (Maha)	150 MW 200 MW 100 MW 10 MW 200 MW	Gas Turbine - Natural Gas	200 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 125 MW 10 MW	Coal Power Plant	300 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 200 MW 10 MW	Gas Turbine - Natural Gas Coal Power Plant *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	200 MW 2x300 MW *(300) MW* *(300) MW*

9.2.1 System Capacity Distribution

Reference case capacity additions by plant type are summarised in five-year periods in the Table 9.2 and a comparison with the base case is given.

Table 9.2 – Capacity Additions Comparison between Reference Case and Base Case

Type of Plant	2025-2029		2030-2034		2035-2039		2040-2044		Total Capacity Addition			
	Ref	Base	Ref	Base	Ref	Base	Ref	Base	Ref		Base	
	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	MW	%
RE	1,775	2,735	1,520	2,600	1,705	2,530	2,325	2,850	7,325	55	10,715	64
GT	-	-	1,430	330	900	800	500	1,200	2,830	21	2,330	14
IC Eng.	200	200	-	-	200	200	-	200	400	3	600	4
CCY	465	465	-	-	-	-	-	-	465	4	465	3
Nuclear	-	-	-	-	-	-	-	600	-	-	600	4
Coal	-	-	-	-	300	-	1,200	-	1,500	11	-	-
PSPP		-	-	600	-	-	600	-	600	5	600	4
BESS	105	305	50	450	-	100	-	50	155	1	905	5
HVDC	-	-	-	-	-	500	-	-	-	-	500	3
Total	**2,545**	**3,705**	**3,000**	**3,980**	**3,105**	**4,130**	**4,625**	**4,900**	**13,275**	**100**	**16,715**	**100**

The reference case plan is comprised of a mix of thermal and renewable power plants. major hydro and other renewable energy additions amount to 55% of the total capacity additions in the planning horizon while it is 64% in the base case plan. Thermal capacity additions include 11% of coal based power plants 28% of natural gas based combined cycles/gas turbines/gas engines while the base case contains 4% from nuclear power and 21% of natural gas/H_2 based combined cycles/gas turbines/gas engines. 5% capacity addition of pumped hydro power plant and 1% from battery storage are also included in the reference case whereas it is 4% and 5% respectively in base case which shows significant reduction in battery storage capacities in the reference case. It could be observed that the Base Case contains 905 MW of battery storage and 600 MW of pumped storage while the reference case contains only 155 MW of battery storage and 600 MW of pumped storage. This aspect mainly contributes to the cost difference between the two cases. When compared with the base case plan, the reference case contains 3,440 MW less capacity additions mainly due the reduction in ORE and energy storage capacities in the planning horizon.

Future capacity mix of the reference case is graphically represented in Figure 9.1

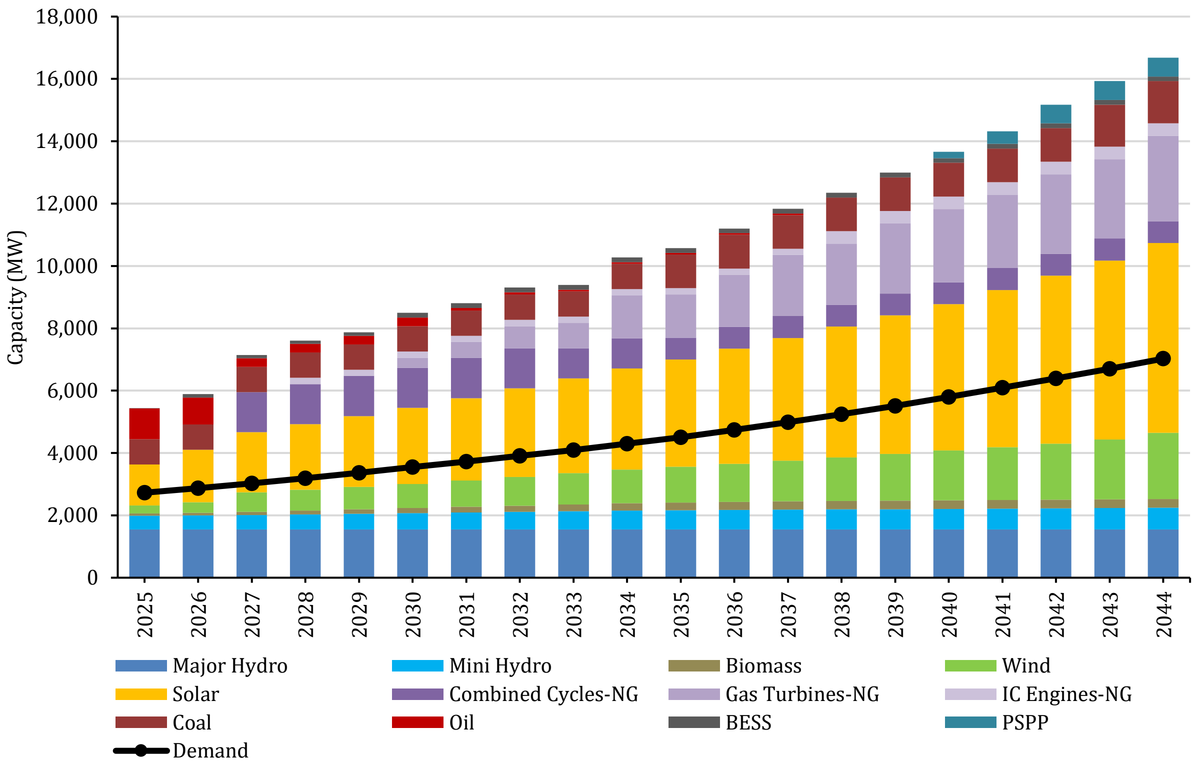


Figure 9.1 - Cumulative Capacity Additions by Plant Type

9.2.2 System Energy Share

Future energy supply mix of the reference case is graphically represented in Figure 9.2.

From 2027 onwards, a 60% renewable energy share is maintained, encompassing major hydro, mini hydro, solar, wind, and biomass sources. Throughout the planning horizon, the share of major hydro generation is set to gradually decrease, starting from 29% in 2025 and reducing to 12% by 2044. To sustain the 60% renewable energy share, the contribution from other renewable energy sources (ORE) is increased, with solar energy playing a significant role in this growth.

As for thermal power plants, during initial 2 years of the planning horizon major energy contribution comes from oil and coal based thermal generation, and beyond 2027, NG and Coal based power plants become the major thermal energy contributors of the system. Oil energy share is decreased and becomes negligible with the gradual retirement of oil plants. Energy share from coal and NG are maintained in the 20% range each.

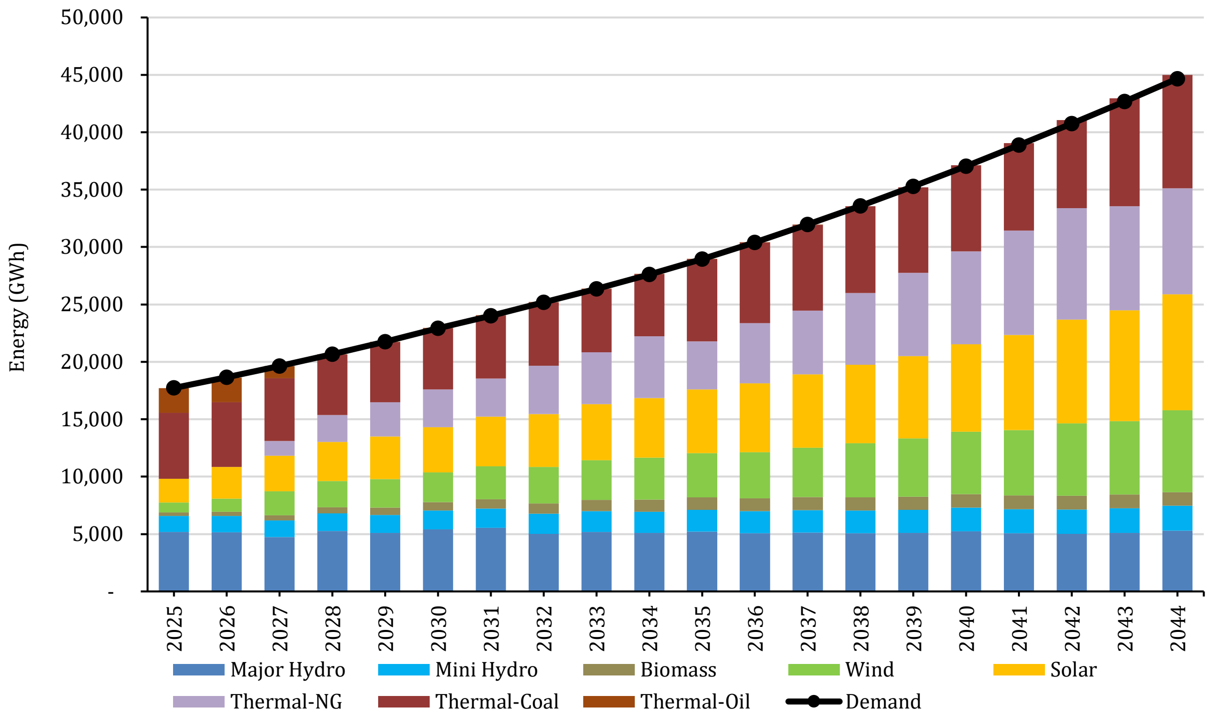


Figure 9.2 - Energy Mix over Next 20 Years in Reference Case

9.2.3 Cost Comparison with Base Case

Compared with the base case plan, reference case shows the USD 846 million present value cost decrement over the planning horizon.

Reference case reaches 60% RE by 2027 and maintains approximately the same share throughout the horizon complying with the least cost principles whereas in the Base Case, the policy target of 70% RE has to be met with adding substantial capacity of energy storage. As a result, a considerable increase of investment cost is observed in the base case compared to the reference case. In contrast, the base case considers much higher contribution from renewable energy sources so that the operation cost significantly reducing compared to the reference case. However, the investment cost increase of Base Case compared to Reference Case is much higher than the operation cost decrease achieved in the Base Case, thus the reference case indicates a substantially low total cost compared to the Base Case. Cost comparisons are presented in Table 9.3.

Table 9.3 - Present Value Cost Comparison between Reference Case and Base Case (in million USD)

Scenario	Investment Cost	Operation Cost	Total Cost
Reference Case	6,462	7,782	14,244
Base Case	9,171	5,918	15,090
Difference with Base Case	-2709	1863	-846

9.2.4 Comparison of CO_2 Emissions with Base Case

Reference case contains significant amount of generation from coal power plants. As a result, a large amount of environmental emissions are observed limiting the ability of the country to maintain a low carbon footprint. In contrast, the development of the base case considers much higher contribution from renewable energy sources and natural gas based generation so that the transition to a low carbon future is enabled significantly reducing the carbon intensity of the sector. CO_2 emissions of the reference case in specific years are presented in Table 9.4 and detailed results on the environmental implications are presented in the Chapter 11.

Table 9.4 - CO_2 Emissions Comparison in Million Tonne

Scenario	2030	2035	2,040	2044
Reference Case	7.3	9.9	12.5	15.8
Base Case	5.9	6.7	7.6	4.2
Difference with Base Case	1.4	3.2	4.9	11.6

CHAPTER 10
BASE CASE SCENARIO

10.1 Background

In the long-term generation expansion planning studies Base Case scenario, among other scenarios, is the policy constrained, technically feasible generation expansion scenario which demonstrates the least economical cost to the country. Subsequent to extensive planning studies as described in Chapter 8, "Scenario 3 : Maintain 70% RE from 2030 onwards, with 500 MW HVDC interconnection, with Nuclear Power, no coal capacity additions" was selected as the Base Case scenario for the 2025 – 2044 planning cycle (Referred as Base Case scenario hereinafter) . Following are the key features of the scenario.

a) 70% of the energy generated in Sri Lanka comes from renewable sources from 2030 onwards
b) Future thermal power additions are from natural gas up to 2035 and afterwards hydrogen blended (25% - 30% by volume) natural gas are introduced.
c) First pumped storage power plant of 3x200 MW is added to the system in 2034.
d) 500 MW HVDC interconnection with India is added to the system in 2039.
e) 600 MW nuclear power plant is introduced to the system at the end of the planning horizon in 2044 upon retirement of all units of Lakvijaya coal power plant.

The total present value cost of the Base Case scenario for the period 2025 – 2044 is USD 15,090 million based on the discount rate of 10%. It should be noted that in long term generation expansion studies, only the costs which affect future decision-making process are considered. Additionally, the cost to be incurred for developing the essential transmission infrastructure for each project would be considered in the transmission planning studies subsequent to the generation expansion plan.

This chapter presents an analysis of the results of the Base Case scenario including the capacity additions expected within the horizon, system energy and capacity balance, energy and capacity shares, fuel requirement, operational and maintenance cost and reliability indices. Furthermore, operational analysis of the Base Case scenario is also delineated.

10.2 Base Case Scenario

The resource and technology wise capacity additions required in each year of the study horizon with respect to the Base Case scenario is illustrated in Table 10.1. Furthermore, Table 10.2 presents technology wise annual breakdown of additions and retirements of power plant capacities in the Base Case scenario. Table 10.3 portray annual ORE capacity additions and cumulative ORE capacity of the Base Case scenario.

Table 10.1 – Base Case Scenario 2025-2044

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b) (d)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c) (e) (f)	
2025	Distribution Connected Embedded Solar	150 MW	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Solar	**50 MW**		
	Wind	**10 MW**		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Battery Energy Storage	5 MW/10 MWh		
2026	Distribution Connected Embedded Solar	150 MW	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Solar	**220 MW**		
	Wind	**90 MW**	*Retirement of*	
	Mini Hydro	10 MW	*Gas Turbine (GT7)*[2]	*(115) MW*
	Biomass	15 MW		
	Battery Energy Storage (Western Region)[1]	**100 MW/ 100 MWh**	Extensions of plants to be retired[3]	
			Sapugaskanda Station A	68 MW
			Sapugaskanda Station B	72 MW
			Barge Mounted Plant	62 MW
2027	Distribution Connected Embedded Solar	150 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Solar	250 MW		
	Wind	260 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
2028	Distribution Connected Embedded Solar	150 MW	**IC Engine Power Plant - Natural Gas**	**200 MW**
	Grid Connected Solar	300 MW		
	Wind	200 MW		
	Mini Hydro	20 MW		
	Biomass	20 MW		
	Battery Energy Storage (Southern Region) [4]	100 MW/ 400MWh		
2029	Distribution Connected Embedded Solar	150 MW		
	Grid Connected Solar	300 MW		
	Wind	150 MW		
	Mini Hydro	20 MW		
	Biomass	20 MW		
	Battery Energy Storage[4]	100 MW/ 400MWh		
2030	Distribution Connected Embedded Solar	150 MW	**Gas Turbine – Kelanitissa**	**130 MW**
	Grid Connected Solar	300 MW		
	Wind	150 MW		
	Mini Hydro	20 MW		
	Biomass	20 MW		
	Battery Energy Storage (Western Region) [4]	50 MW/ 50 MWh		
2031	Distribution Connected Embedded Solar	150 MW	Gas Turbine - Natural Gas	100 MW
	Grid Connected Solar	200 MW		
	Wind	100 MW	*Retirements of*	
	Mini Hydro	20 MW	*Sapugaskanda Station A*	*(68) MW*
	Biomass	20 MW	*Sapugaskanda Station B*	*(72) MW*
	Battery Energy Storage	100 MW/400 MWh	*Barge Mounted Plant*	*(62) MW*
2032	Distribution Connected Embedded Solar	150 MW		
	Grid Connected Solar	200 MW		
	Wind	100 MW		
	Mini Hydro	20 MW		
	Biomass	20 MW		
	Battery Energy Storage	200 MW/800 MWh		
2033	Distribution Connected Embedded Solar	150 MW	Gas Turbine - Natural Gas	100 MW
	Grid Connected Solar	200 MW		
	Wind	100 MW	*Retirements of*	
	Mini Hydro	20 MW	*Combined Cycle Power Plant (KPS)*	*(165) MW*
	Biomass	20 MW	*Combined Cycle Power Plant (KPS-2)*	*(163) MW*
	Battery Energy Storage	100 MW/ 400MWh	*Uthuru Janani Power Plant*	*(26.7) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b) (d)	THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c) (e) (f)
2034	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Pumped Storage Power Plant (Maha) 600 MW	
2035	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend 300 MW *Retirement of* *West Coast Combined Cycle Power Plant (300) MW*
2036	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend 300 MW
2037	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW Battery Energy Storage 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend 200 MW
2038	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend 200 MW
2039	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW	HVDC Interconnection 500 MW
2040	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend 200 MW
2041	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Mini Hydro 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend 200 MW Gas Turbine - Natural Gas & Hydrogen Blend 300 MW *Retirement of* *Lakvijaya Coal Power Plant Unit 1 (300) MW*
2042	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Mini Hydro 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend 300 MW
2043	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Wind-Offshore 500 MW Mini Hydro 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend 200 MW
2044	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 300 MW Mini Hydro 10 MW Battery Energy Storage 50 MW/200 MWh	Gas Turbine - Natural Gas & Hydrogen Blend 200 MW Nuclear Power Plant 600 MW *Retirements of* *Lakvijaya Coal Power Plant Unit 2 (300) MW* *Lakvijaya Coal Power Plant Unit 3 (300) MW*

General Notes

a) All plant capacities (MW) shown are the Gross Capacities. Committed Power Projects are shown in bold text and retiring projects are shown in italics with their capacity in brackets.

b) Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities mentioned in the table. Higher capacity additions will be evaluated case by case.

All future wind and grid connected solar shall be procured with necessary grid support capabilities as stipulated in Grid Code. It is required to procure at least 90% of future wind and grid connected solar capacity as projects with capabilities to operate according to the dispatch instructions from national system control centre.

The capacity addition of battery energy storage devices is mainly to provide energy shifting requirements. It could either be developed as stand-alone or co-located with large scale solar parks with dispatch capability from national system control centre. Any additional battery storage capacity could be accommodated at detailed studies after evaluating grid support services requirement such as frequency regulation.

All renewable and storage capacity additions are to be made available during the respective year.

The retirement years of renewable energy capacities are not indicated. However, after the expiry of the PPA, they are expected to be refurbished or replaced with similar capacity from same renewable energy technology.

The retirement years of battery energy storage systems are not indicated. However, they are expected to be replaced with similar capacity, at the end of their lifetime.

c) With the development of LNG supply infrastructure, the existing West Coast power plant (300 MW) and two Kelanithissa combined cycle plants (165 MW and 163 MW) are expected to be converted to natural gas in the mid of 2027. However, the viability of conversion of each power plant should be evaluated separately at the time of the natural gas availability.

Considering the heavy dependency in future on liquefied natural gas as a fuel for electricity generation, all Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply.

All new natural gas fired power plants should have the capability to operate from synthetic fuels such as Hydrogen, to satisfy the policy requirement of achieving carbon neutrality by 2050.

All new natural gas based Combined Cycle Power plants should be technically, operationally and contractually capable of being operated regularly between simple cycle and combined cycle operations.

Dates of all plant additions as contained in the table are the dates considered for planning studies, and considered as added at the beginning (as at 1st January) of the respective year.

(For example, a generating capacity addition indicated for year 2026 implies that the plant has been considered commissioned from the 1st of January 2026). However, for committed power projects actual commissioning month has been considered based on the present progress of the project.

Retirement dates of existing firm capacity plants are dates considered as inputs to planning studies. For existing power plants, the actual retirement month/PPA expiry month were considered for studies.

However, the ACTUAL retirement of all power plants is to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

d) Moragolla Power Plant (30 MW) which is under construction is to be commissioned during 2024. Hence it is not shown in the base case and is considered as an existing plant.

e) 17 MWx 4 units of Kelanitissa small GTs are considered to be retired during the year 2024 for planning studies considering the extended lifetime. However, two number of units are expected to be kept as backup for Colombo power restoration in case of an island-wide power failure.

f) Short term supplementary power requirement is not seen during the coming years in this plan. However, short-term supplementary capacity requirement under different contingency events are assessed in the contingency analysis chapter of the LCLTGEP 2025-2044 report. Such requirements too shall be appropriately considered prior to initiating procurement.

Extension of the contracts of existing capacities could be considered as appropriate within the legal framework to meet short term requirement. Technology of supplementary capacity can be opened for both Gas Turbine and IC engine technology or any other dispatchable firm power technology as appropriate at the time of the procurement. Fuel option can be specified as appropriate at the time of procurement for suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.

Specific Notes

1. The Battery Energy Storage system shall be developed primarily to cater immediate requirements of frequency related services and restoration services.

2. Upon retirement of GT7 in 2026, the possibility of retrofitting the asset as a synchronous condenser shall be evaluated.

3. Plant life extensions of Sapaugaskanda Station A, Sapugaskanda Station B and Barge Power Plant was considered in planning studies and these extensions become viable considering the relevant refurbishment costs of each plant.

4. Due to the unforeseen growth in distributed renewable energy resources by the time of approval of LTGEP 2025-2044, provision is allowed to advance/expedite the procurement of these storage capacities considering the declined prices of battery energy storage systems.

It should be specifically noted that the capacity additions depicted in Table 10.1 are strictly derived based on the demand forecast presented in Chapter 3 - Table 3. 3. In case of any drastic deviation in the actual demand from the forecasted demand due to unforeseen circumstances such as an economic crisis, decisions taken based on the Base Case scenario should be arrived after re-evaluating the situation on case by case basis.

Table 10.2 - Annual Capacity Additions

Year	**Gross Capacity Addition (MW)**									
	GT	**ICE**	**Combined Cycle**	**Nuclear**	**Major Hydro**	**ORE[1]**	**BESS[2]**	**PSPP**	**HVDC Interconnection**	**Existing Thermal Plant Retirements**
2024	-	-	-		30	159	-	-	-	
2025	-	-	115	-	-	230	5	-	-	
2026	-	-	235	-	-	485	100	-	-	(115)
2027	-	-	115	-	-	690	-	-	-	
2028	-	200	-	-	-	690	100	-	-	
2029	-	-	-	-	-	640	100	-	-	
2030	130	-	-	-	-	640	50	-	-	
2031	100	-	-	-	-	490	100	-	-	(202)
2032	-	-	-	-	-	490	200	-	-	
2033	100	-	-	-	-	490	100	-	-	(355)
2034	-	-	-	-	-	490	-	600	-	
2035	300	-	-	-	-	470	-	-	-	(300)
2036	300	-	-	-	-	520	-	-	-	
2037	200	-	-	-	-	520	100	-	-	
2038	-	200	-	-	-	510	-	-	-	
2039	-	-	-	-	-	510	-	-	500	
2040	200	-	-	-	-	510	-	-	-	
2041	500	-	-	-	-	460	-	-	-	(300)
2042	300	-	-	-	-	460	-	-	-	
2043	-	200	-	-	-	960	-	-	-	
2044	200	-	-	600	-	460	50	-	-	(600)
Total	**2,330**	**600**	**465**	**600**	**-**	**10,715**	**905**	**600**	**500**	**(1,872)**

[1]ORE plants retired within the horizon is assumed to be replaced by plants of same capacity in same technology. These additions are not indicated here.
[2]BESS retired within the horizon is assumed to be replaced by BESS of same capacity and these additions are not indicated here.

Table 10.3 - Annual ORE Capacity Additions and Cumulative Capacity

Year	Mini Hydro (MW)		Wind (MW)		Biomass (MW)		Solar (MW)	
	Addition	Cumulative	Addition	Cumulative	Addition	Cumulative	Addition	Cumulative
2024	-	419	-	267	-	54	159	1,112
2025	10	429	10	277	10	64	200	1,312
2026	10	439	90	367	15	79	370	1,682
2027	10	449	260	627	20	99	400	2,082
2028	20	469	200	827	20	119	450	2,532
2029	20	489	150	977	20	139	450	2,982
2030	20	509	150	1,127	20	159	450	3,432
2031	20	529	100	1,227	20	179	350	3,782
2032	20	549	100	1,327	20	199	350	4,132
2033	20	569	100	1,427	20	219	350	4,482
2034	20	589	100	1,527	20	239	350	4,832
2035	10	599	100	1,627	10	249	350	5,182
2036	10	609	100	1,727	10	259	400	5,582
2037	10	619	100	1,827	10	269	400	5,982
2038	10	629	100	1,927	-	269	400	6,382
2039	10	639	100	2,027	-	269	400	6,782
2040	10	649	100	2,127	-	269	400	7,182
2041	10	659	-	2,127	-	269	450	7,632
2042	10	669	-	2,127	-	269	450	8,082
2043	10	679	500	2,627	-	269	450	8,532
2044	10	689	-	2,627	-	269	450	8,982
Total	**270**	**689**	**2,360**	**2,627**	**215**	**269**	**7,870**	**8,982**

Note: Plants retired within the horizon is assumed to be replaced by plants of same capacity in same technology. These additions are not indicated here.

10.3 System Capacity Distribution

In accordance with the national policies as well as international bindings, renewable energy sources dominate the future power system during 2025 – 2044 horizon. ORE capacity additions are prominent in meeting the growing electricity demand. Along with the ORE development energy storage options, flexible generation options and firm capacities are adequately added to the system in order to ensure system stability and reliability.

At the end of 2023, total installed capacity of the Sri Lankan power system is 5,194 MW (with rooftop solar) from which 3,501 MW accounting for 67% of the installed capacity is dispatchable and the remaining 33% is non-dispatchable. Progressing through the horizon due to robust ORE advancement, dispatchable capacity from hydro and thermal sources gradually diminishes below 30% by 2044. Hence future capacity additions from grid scale solar and wind resources are required to be controlled from NSCC as dispatchable sources.

By December 2023 major hydro capacity share is 27% but as economically feasible major hydro resources are exhausted in Sri Lanka, new hydro capacity additions to the system are disregarded. Hence by 2030 the capacity share decreases to 16% and drops further to 8% by 2044.

End-of-year ORE share of 33% in 2023 rapidly increases to 54% by 2030 due to progressive renewable energy commitments in par with the policy directives. When reaching the end of horizon this share further rises to 62%. The prominent energy source that contributes to the increase is solar, with net capacity addition of 7,870 MWs, followed by 2,360 MW of wind capacity addition during the planning horizon. The mini hydro share shrinks in the long run to 4% in 2044 compared to 8% in 2023 end, as a result of limited resource availability while biomass maintains a fairly consistent capacity share of 1-2% throughout the horizon.

Even though currently (by the end of 2023) coal capacity share is 17%, with the policy directive to cease addition of coal capacities, together with high renewable penetration, coal capacity share reduces to 8% by 2030 and phases out by 2044 with the retirement of Lakvijaya coal power plant. Some of the major existing oil based thermal power plants are converted to natural gas in the initial stages of the study horizon while others are retired as they reach the end of their economic life. As a result, oil based generation capacity share of 23% in 2023 reduces to 3% by 2030 and completely discontinued afterwards.

All thermal firm capacity additions during 2025-2044 horizon are from clean energy sources. Up to 2034, 330 MW of gas turbine power plants, 200 MW IC engine power plants and 700 MW of combined cycle power plants are added to the system. Beyond 2034 hydrogen blended natural gas power plants are introduced and 2,000 MW of gas turbine power plants along with 400 MW of IC engine power plants are added. Additionally with the retirement of coal power plant, 600 MW nuclear power plant is introduced to the system in 2044.

In order to balance out the intermittencies and seasonality inherent to VRE power generation, several energy storage options are integrated into the system. First PSPP of 600 MW is expected to be commissioned by 2034, besides 905 MWs of grid scale BESS is required to incorporate to the system during the study horizon. However, BESS requirement beyond 2030 needs to be validated based on the system requirements due to the actual progress of the VRE development.

Figure 10.1 illustrates the annual capacity additions based on plant type/technology and detailed annual capacity balance of the system is demonstrated in Annex 10.1.

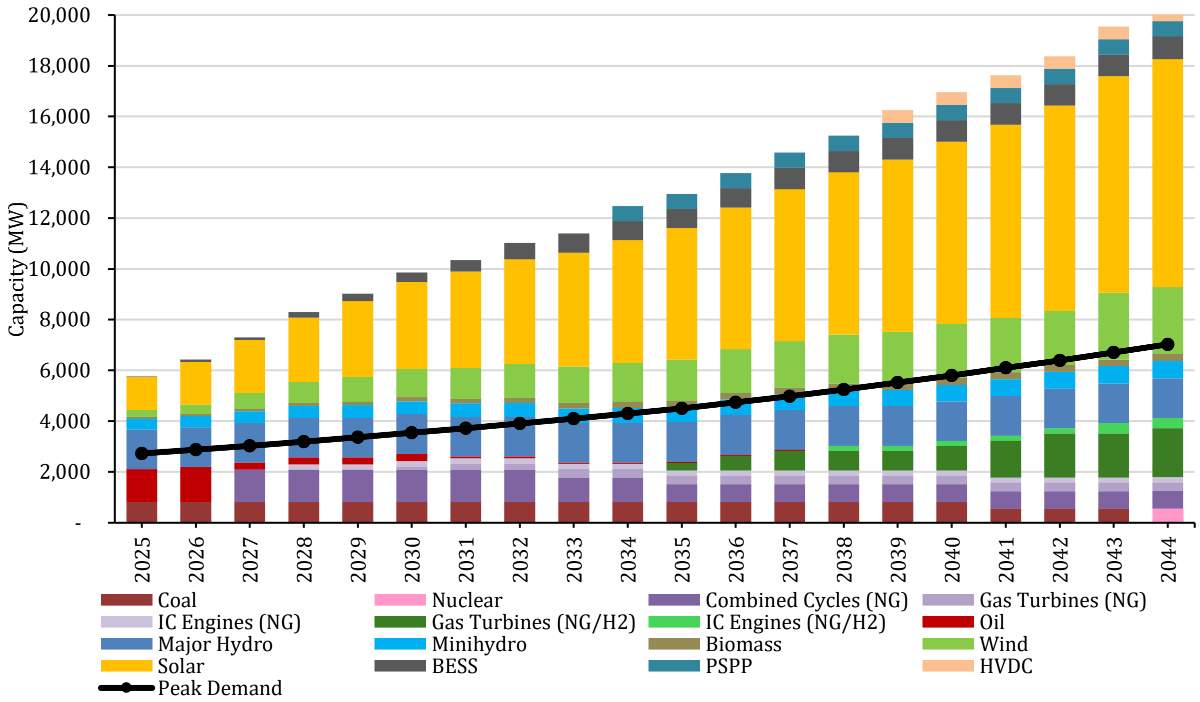


Figure 10.1 – Cumulative Capacity by Plant Type

Figure 10.2 presents the percentage share of capacity categorized by plant type/technology. Figure 10.3 describes source wise capacity distribution over the study horizon.

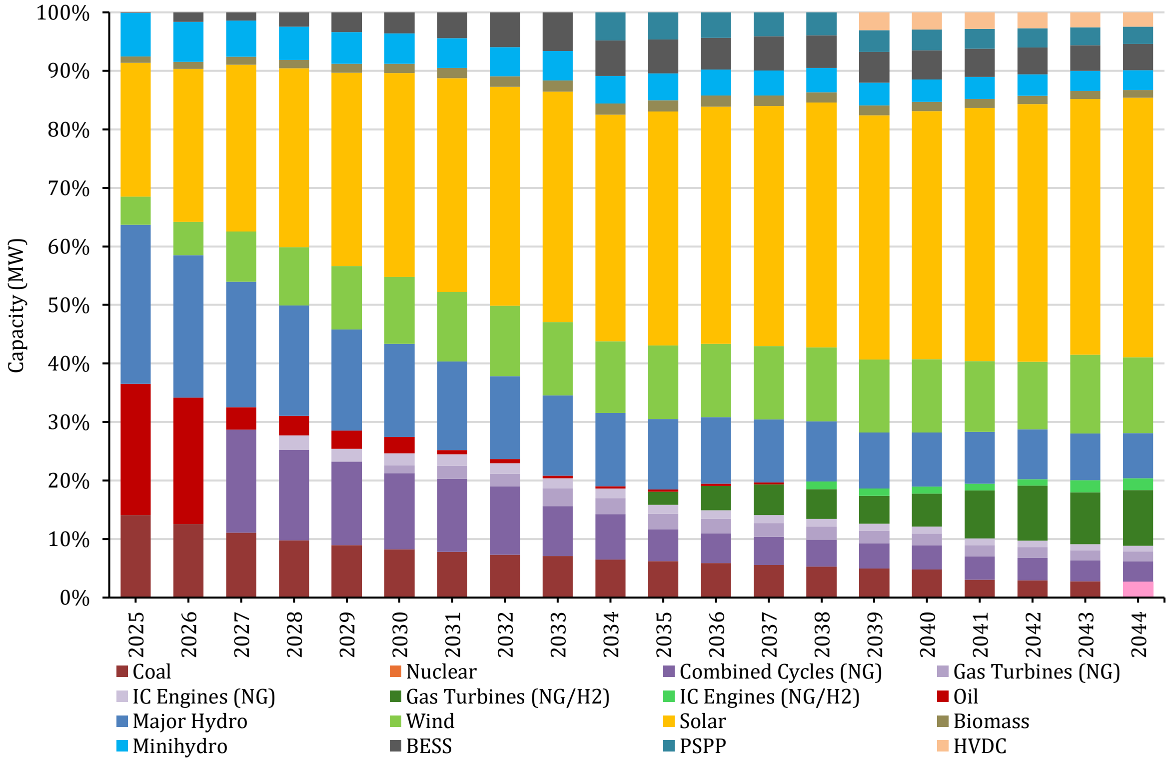


Figure 10.2 – Cumulative Capacity Share by Plant Type

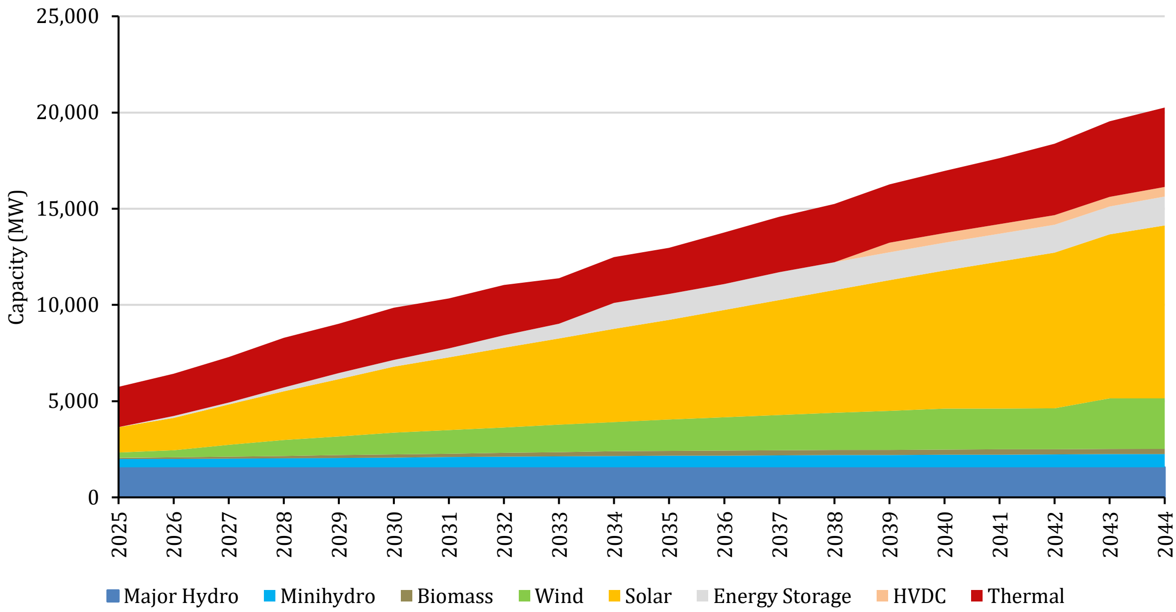


Figure 10.3 - Source wise Capacity Contribution

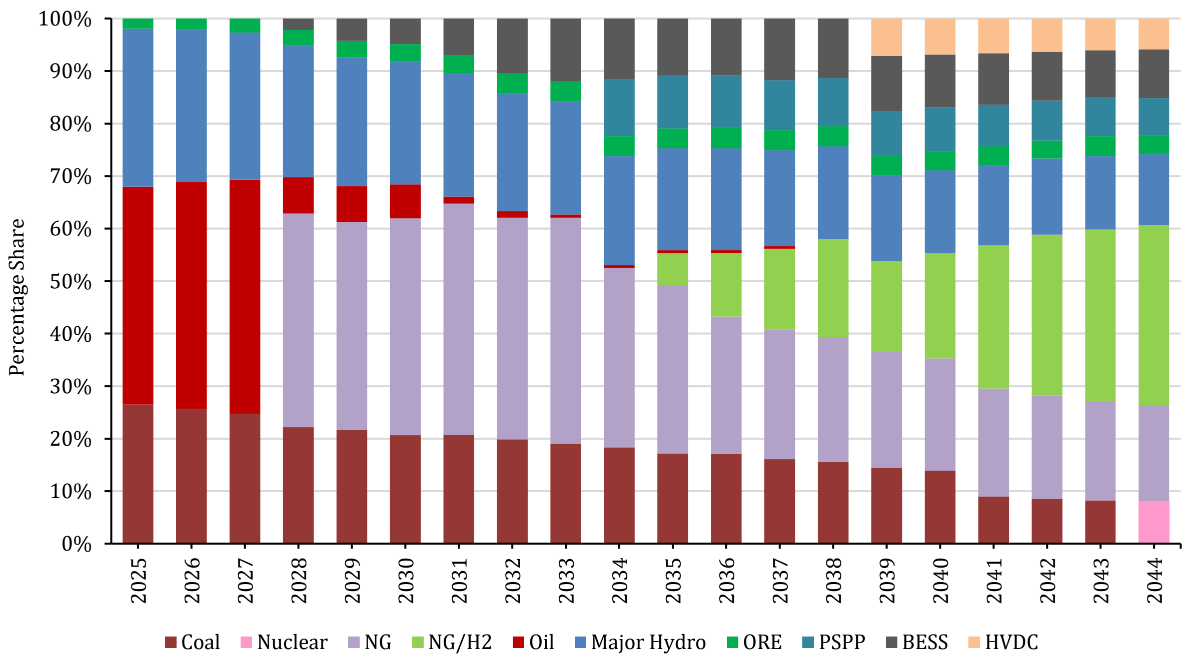


Figure 10.4 - Source wise Firm Capacity Share

Figure 10.4 represents the firm capacity variation of the Base Case scenario over the 20-year study horizon. Thermal and major hydro power plants, along with energy storage systems, primarily provide firm capacity to the grid, while the contribution from ORE sources is significantly lower. The most critical period for maintaining system reliability is during the night peak, as the energy system transitions to being dominated by renewables, especially solar, which does not generate power during nighttime hours. Ensuring firm capacity during this time is essential for system reliability.

Unlike the nominal capacity variation dominated by renewable energy, other sources overshadow renewable energy in firm capacity share. ORE firm capacity contribution is as low as 2%-4% during the period. Major hydro firm capacity provision decreases from 30% in 2025 to 23% in 2030 and 14% in 2044 as there are no future major hydro additions to the system. Coal share which begins with 26% in 2025 gradually decreases and reaches 14% in 2040 and becomes zero by 2043 with the retirement of the Lakvijaya plant. Firm capacity contribution from oil power plants which is approximately 40% in 2025 & 2026 transfers to NG fired plants from 2027 with the conversion of major oil fired plants to natural gas. Power plants fired with natural gas and hydrogen blended natural gas maintain a firm capacity share in the range of 34% to 44% until the initiation of unit wise retirement of Lakvijaya plant in 2041. Between 2041 & 2044 this share varies around 50%. The establishment of nuclear power plant in 2044 offers an 8% firm capacity share while HVDC interconnection provides 6%-7% firm capacity share with its commissioning in 2039. The firm capacity share provided by energy storage options gradually increases to 22% by 2035 and continues to maintain 16%-21% share afterwords.

Table 10.4 delineates a summary of important capacity attributes in the milestone years of the planning horizon. It is observed that ahead 2030 RE share in the installed capacity revolves around 70%. Firm capacity is 40% from the installed capacity in 2030 and in the following years 2035 & 2040 it is decreased to 37% and 34% respectively and in 2044 also firm capacity share retain at 34%.

Table 10.4 - Capacity Distribution for Milestone Years

Year	**2030**	**2035**	**2040**	**2044**
Major Hydro Installed Capacity (MW)	1,563	1,563	1,563	1,563
ORE Installed Capacity (MW)	5,227	7,657	10,227	12,567
Total Renewable Installed Capacity (MW)	**6,790**	**9,220**	**11,790**	**14,130**
Total Thermal Installed Capacity (MW)	2,705	2,392	3,219	4,126
Total Energy Storage Installed Capacity (MW)	355	1,350	1,450	1,500
Interconnection Installed Capacity (MW)			500	500
Total Installed Capacity (MW)	**9,850**	**12,962**	**16,959**	**20,256**
Total Firm Installed Capacity (MW)	3,919	4,723	5,823	6,804
Night Peak Demand (MW)	3,411	4,219	5,286	6,275
System Peak Demand (MW)[1]	3,548	4,507	5,798	7,026

[1]System peak demand occurs during the daytime

10.4 System Energy Distribution

In 2023, 51% of total electricity generation came from renewable energy (RE) sources, including 22% from ORE sources, while the remaining 49% was generated by thermal sources. As the study horizon progresses, the share of RE grows steadily, reaching 70% by 2030, in line with policy guidelines, and remains at this level throughout the latter years. The demand increase is largely met by variable renewable energy (VRE) sources, VRE's share in generation is set to increase from 17% in 2025 to 40% in 2030, eventually reaching beyond 50% by the end of the period. Consequently, the share of thermal generation decreases to 30% by 2030 and remains stable, primarily providing flexibility and reliability to the system.

In 2023, coal accounted for 30% of electricity generation, but its share gradually declines, with all three units of the Lakvijaya power plant set to be retired by 2043, leading to a complete phase-out of coal. Similarly oil, which contributed 20% to generation in 2023, sees a sharp reduction by 2027 with the introduction of natural gas and is completely phased out as all oil power plants are retired gradually.

Energy generated by natural gas and hydrogen blended natural gas varies around 6%-12% up to 2039 and increases to 17% in 2041 due to the retirement of the first coal unit. Its share continues to increase up to 18% by 2044 with the retirement of coal power plant. Once commissioned the nuclear power plant produces 10% of total energy in 2044. Net import of the HVDC interconnection provides 3%-4% of total energy generation during 2039-2044.

Energy mix of the generation which served Sri Lanka's demand over the study horizon is shown in Figure 10.5. Percentage share of the sources in the energy generated within Sri Lanka is shown in Figure 10.6. Annual energy balance is presented in Annex 10.2 and annual generation and respective plant factors under different renewable generation conditions (low, average and high RE) for the Base Case scenario are given in Annex 10.3.

Figure 10.6 portrays a source wise breakdown of RE generation through the study period. In line with the policy directives, renewable energy share in the generation increases to 70% by 2030 and persists throughout the subsequent years. VRE share in the generation will increase over the years from 12% in 2023 to 39% in 2030 and to over 50% by 2044. In contrast, since no future capacity additions of major hydro are planned due to resource scarcity, the share in the generation of major hydro will reduce from 29% share in 2023 to 14% by 2040. Mini hydro share which is 8% in the beginning of the horizon drop to 5% by the end of the horizon due to limited availability of the resource. Biomass share is constant at 2%-3% all through the period.

Additionally, renewable energy curtailment is observed from 2027 onwards and is described in detail in section 10.8.

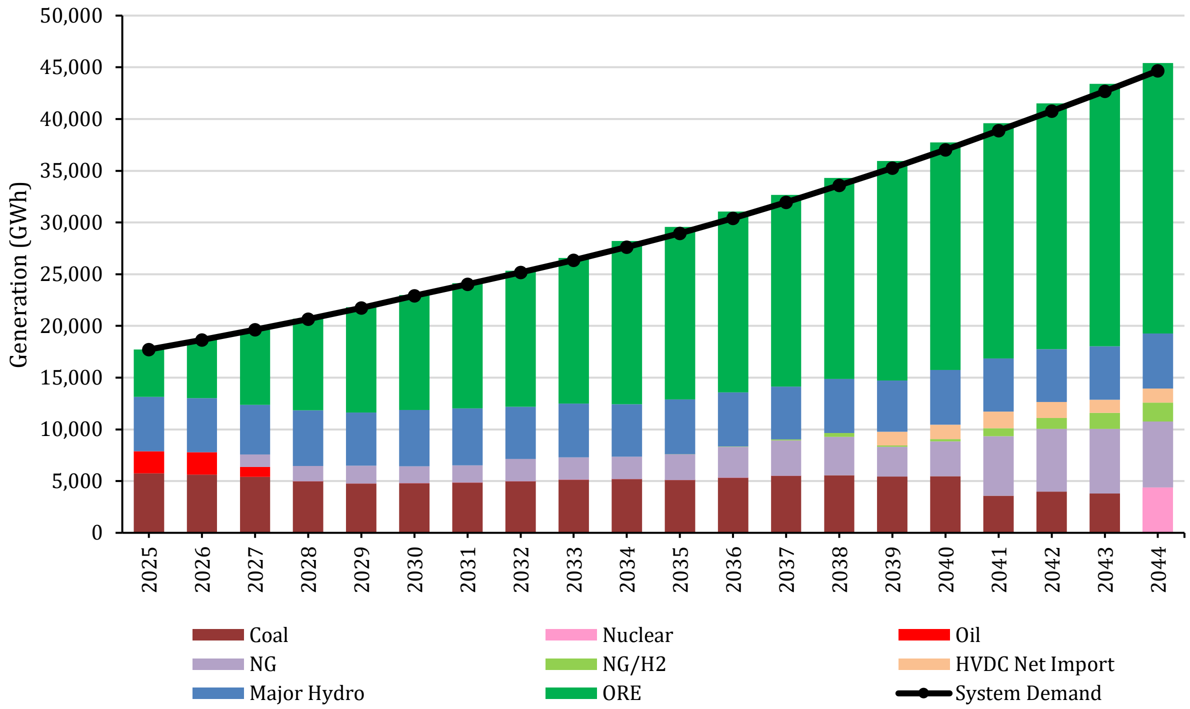


Figure 10.5 – Source wise Energy Mix of Total Generation

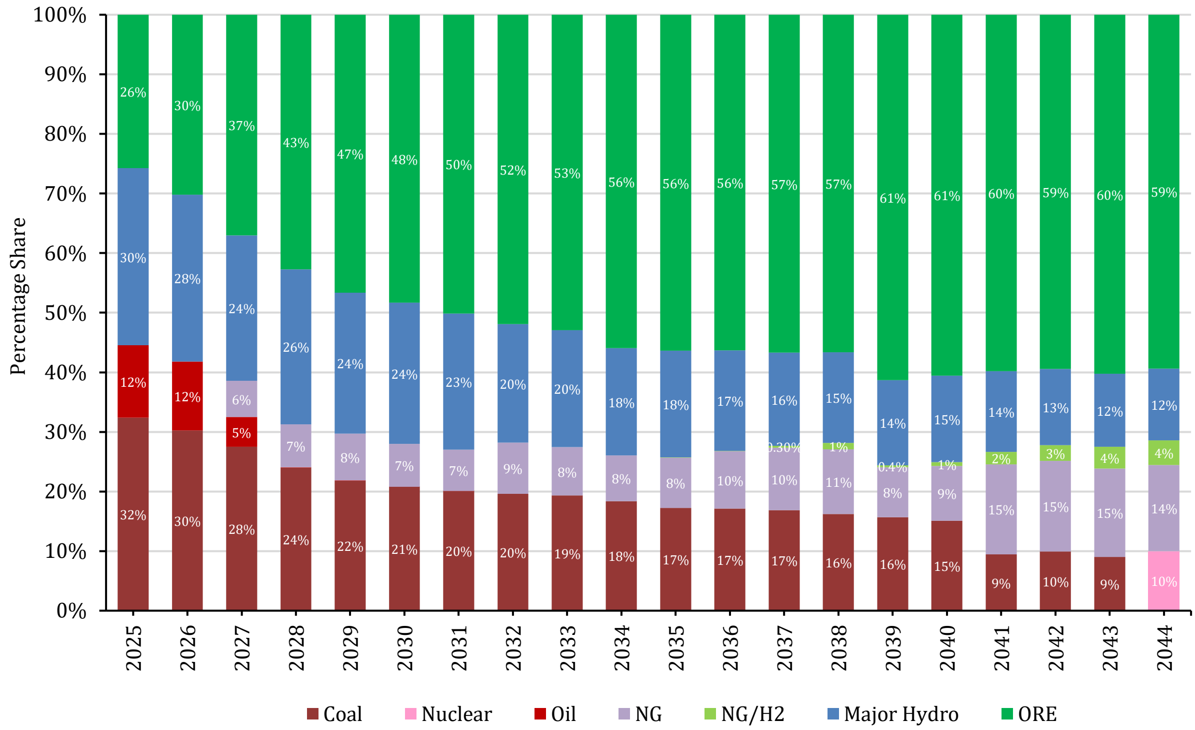


Figure 10.6 - Source wise Energy Share of Generation within Sri Lanka

10.5 System Non-Synchronous Penetration

Due to the increasing integration of renewable energy sources such as wind and solar, more power is injected to the grid, through power electronic inverters. The System Non-Synchronous Penetration (SNSP) refers to the instantaneous measure of the percentage of generation that comes from non-synchronous sources, such as wind, solar, battery storage and HVDC interconnector imports, relative to the system demand. The detailed operational analysis has been conducted allowing System Non-Synchronous Penetration limit to be increased up to 75% of electricity demand. The remaining 25% of the demand is expected to be provided from synchronous generation that provides the required mechanical inertia to the system. The SNSP from generation is gradually increased up to 80% in years beyond 2030. In actual operation it is expected to gradually increase this penetration levels further after reaching satisfactory actual operation of power system at planned SNSP limits. The economic benefits of operating up to 100% SNSP of main scenarios are described in section 8.4.3 of chapter 8. It is mandatory to conduct detailed studies to evaluate the impact on the power system to gradually achieve higher SNSP limits phase by phase. The SNSP distribution of hourly simulations of selected years from the Base Case scenario is depicted in Figure 10.7.

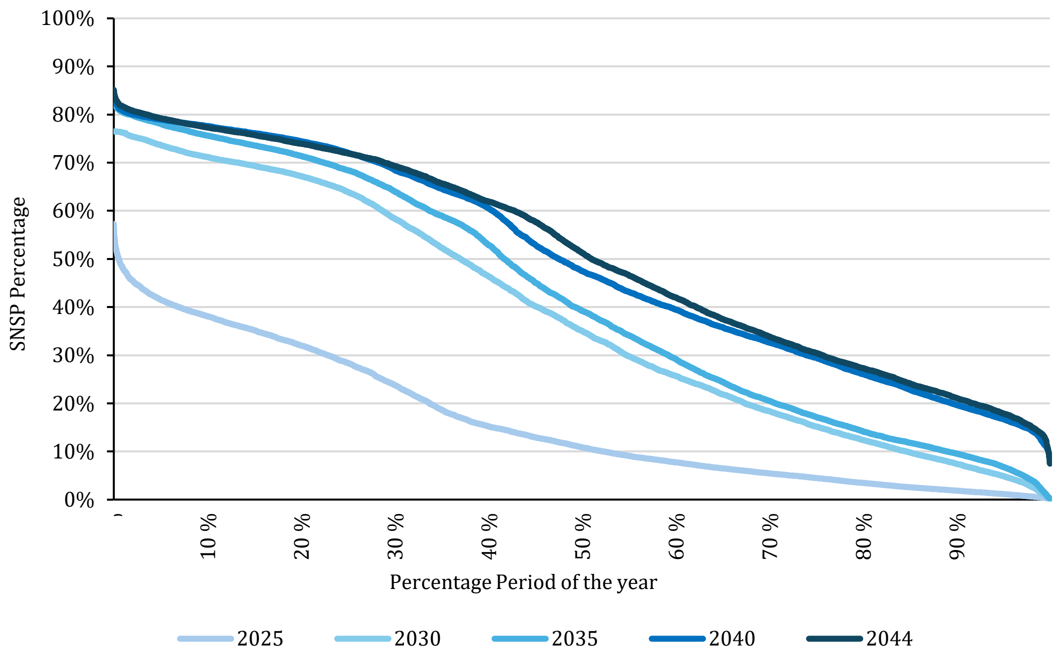


Figure 10.7 - SNSP Distribution of Milestone Years

The system SNSP limits trigger up to 50% during certain holidays in 2025, with the aggressive development of distributed solar systems. This will gradually rise up to 75% in year 2030, with approximately 40% of the hours in a year (i.e. approximately 3,500 hours of a year) operating at high inverter based generation. SNSP levels can reach up to 80% in year 2035, while in year 2044 more than 50% of hours in a year (i.e. approximately 4,400 hours of a year) operating at high inverter based generation. If proper power system reinforcements are not introduced the power system shall be at a vulnerable state for blackouts during a contingency event during these periods.

10.6 Dispatch Patterns in Weekly Load Curve

The power system shall be dominated with renewable energy resources; hence the dispatch shall be seasonal with high dependency on weather related events. The expected weekly system dispatch patterns during different seasons of targeted policy year 2030 are summarized as Figure 10.8. The sample weekly system dispatch patterns during different seasons of year 2044 is illustrated in Figure 10.9.

In addition, weekly dispatch during dry season, high wind season and wet season of years 2025, 2035 and 2040 are depicted in Annex 10.4, Annex 10.5 and Annex 10.6 respectively. It can be seen that each season has unique characteristics driven by weather dependent events.

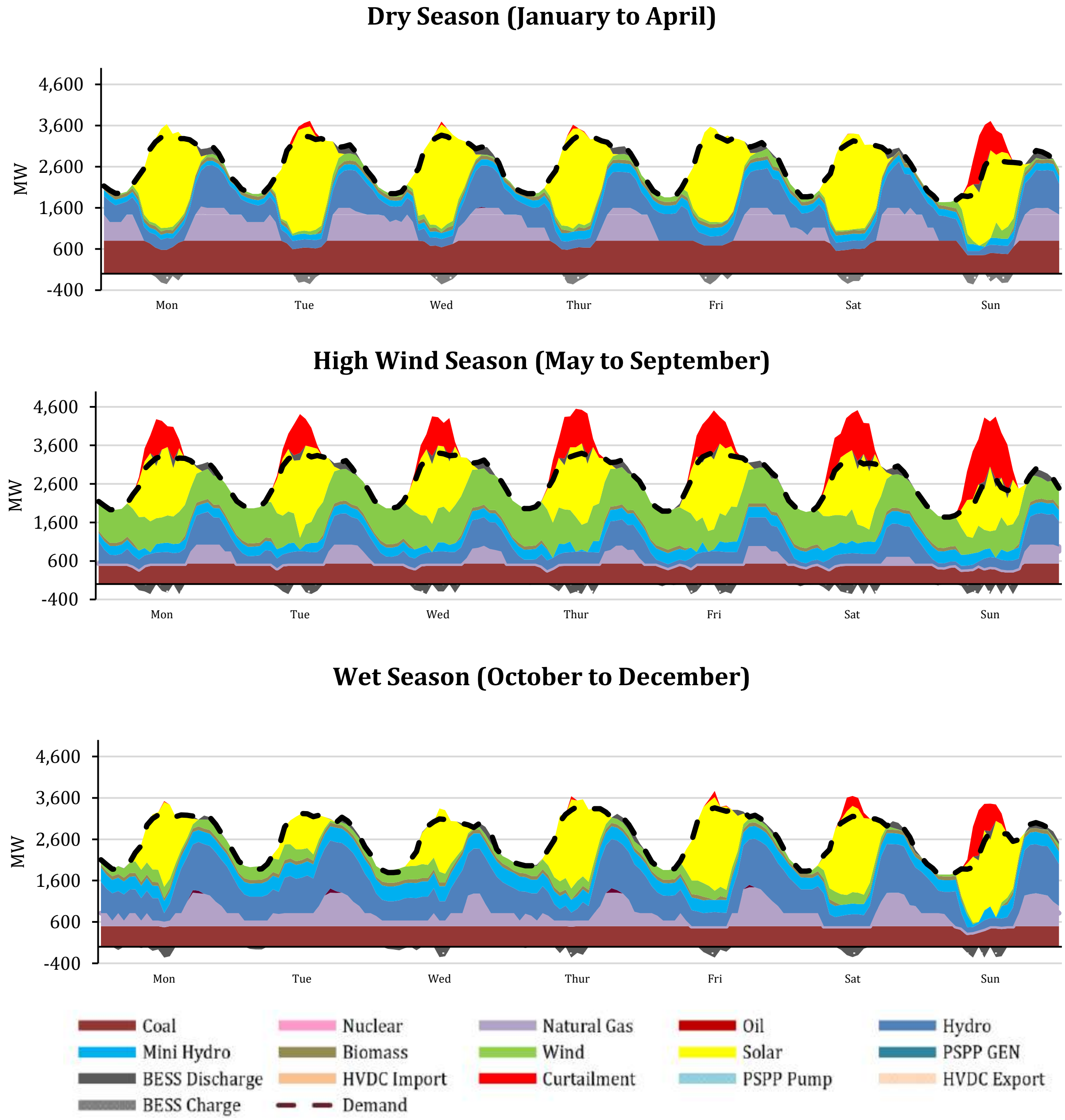


Figure 10.8 - Sample Weekly Dispatch Year 2030

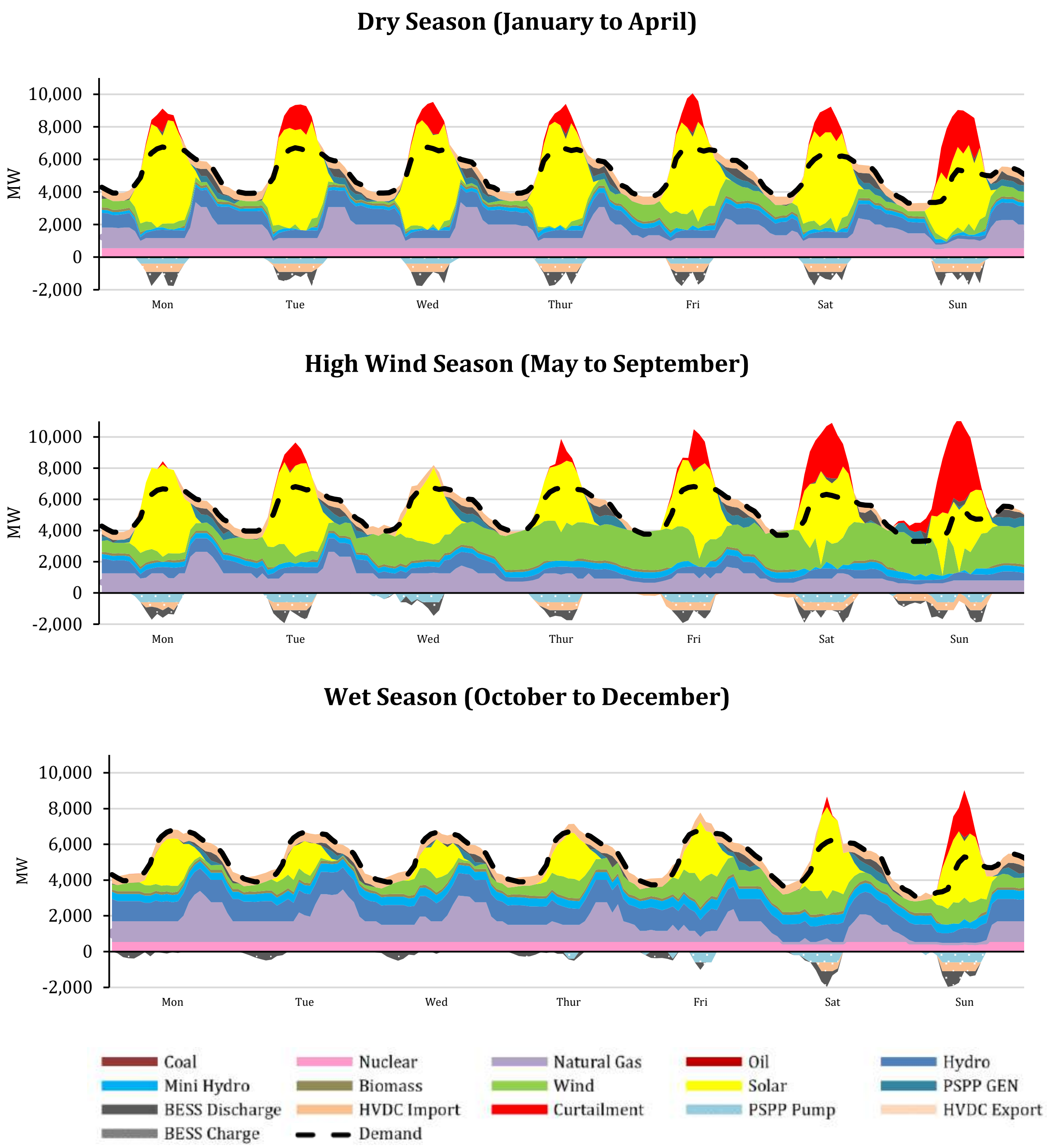


Figure 10.9 - Sample Weekly Dispatch Year 2044

Note: A portion of the natural gas generation shall operate with blended hydrogen in Figure 10.9

During the dry season, coal and nuclear power plants are primarily operated as base load units, providing a steady and continuous supply of electricity. Combined cycle power plants, known for their efficiency, are used to meet both base and intermediate loads, operating with daily cycling patterns to accommodate varying demand. Solar energy production is at its peak during the daytime in this season, and any excess energy generated is stored in batteries or pumped hydro storage systems for use during the night peaks. Wind energy production, however, is generally low during the dry season, and major hydro resources are strategically dispatched during night peak and off-peak periods to balance the system. Curtailments, are primarily observed during the daytime, with the highest occurrences on Sundays or holidays when demand is lower. Once interconnection system is commissioned, it will be used mainly for importing electricity during dry period of the year. Exporting of the excess electricity during day time of this period is also expected.

In the high wind season, at least one coal power unit is typically under maintenance while the remaining units continue to operate as base load plants. This period also provides an ideal window for nuclear power plants to undergo refueling, particularly once these plants are commissioned. The operation of combined cycle power plants is not anticipated during this season until the retirement of coal power plant. Flexible power plants, such as gas engines and gas turbines, are dispatched cyclically to respond to the varying demand. The southwest monsoon brings high wind energy production, which, combined with significant hydro dispatch and average solar production during the daytime, results in a high share of renewable energy generation. During this time, battery energy storage and pumped hydro storage units play a crucial role in energy shifting—storing energy when supply exceeds demand and releasing it when needed—and in frequency regulation throughout the day. Curtailments may occur on both weekdays and weekends, during both daytime and off-peak times., The high wind season allows for the highest export potential through the interconnector, primarily during the daytime when renewable energy generation is abundant.

During the wet season, coal and nuclear power plants continue to operate as base load units, ensuring a stable supply of electricity. Combined cycle power plants are again utilized to serve both base and intermediate loads. Peaking thermal plants, such as gas turbines, are dispatched when solar energy production is low, typically on overcast days. Solar energy production during the wet season can vary, with some days seeing decreased output. Wind energy remains at average levels, while the northeast monsoon and inter-monsoon seasons significantly boost hydro inflows. This increased water availability allows major hydro plants to be dispatched effectively during night peak and off-peak periods, helping to balance the grid. The storage capacity of major reservoirs is strategically managed to ensure they are filled and ready to be utilized in the next dry season. Battery energy storage and pumped hydro storage systems are used to shift excess solar energy production, storing it for later use. Curtailments during the wet season are primarily observed on Sundays during the daytime, with occasional occurrences on weekday daytime.

This seasonal strategy ensures that the power system remains flexible and reliable, optimizing the use of various energy sources and storage solutions to meet demand efficiently throughout the year.

10.7 Renewable Energy Generation

The potential for development of further hydro and biomass resources are limited. Hence in order to achieve 70% renewable energy share by 2030 and maintain the same up to 2044 considerable amount of VRE sources need to be developed. The addition of VRE sources to the system and the increase in share of VRE throughout the planning horizon is illustrated in Figure 10.10.

Solar energy is poised to become the primary contributor to the energy mix in the coming years, with its share expected to rise from 6% today to 34% by 2044. Wind energy, the second-largest contributor, is anticipated to grow from 5% to 19% over the same period. It is observed that VRE share which is at 12% in present day, increases rapidly during the planning period reaching 40% by 2030 and 50% by 2040.

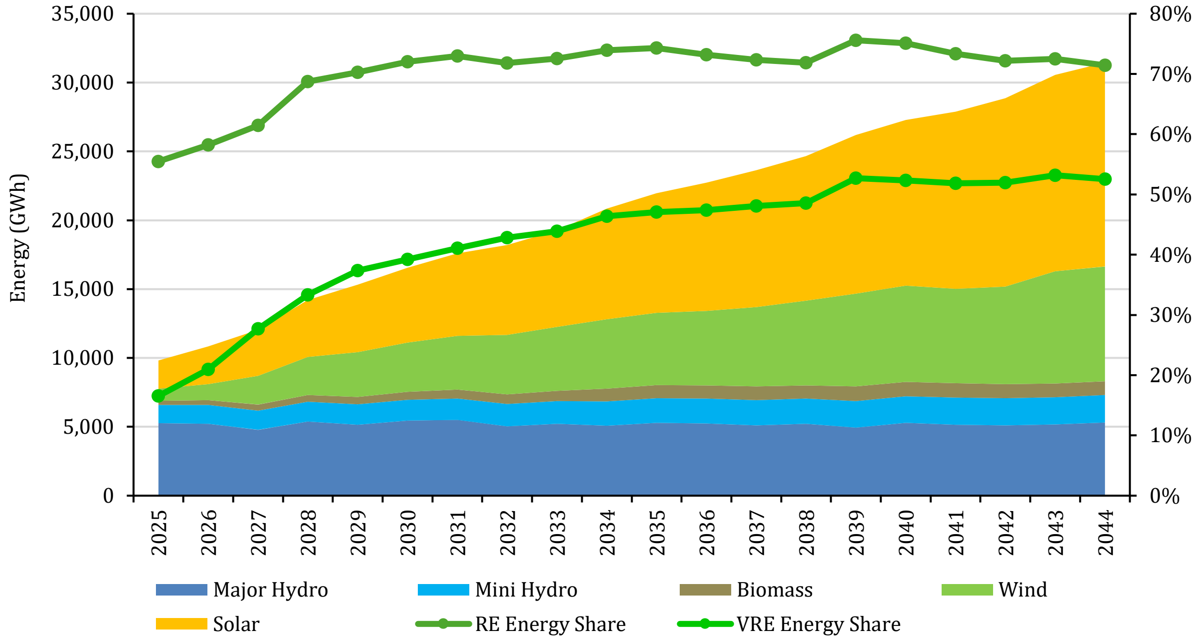


Figure 10.10 - Source wise Renewable Generation, RE Share and VRE Share

According to the classification defined by International Energy Agency (IEA) based on key characteristics and challenges experienced by different systems of different countries with their wind and solar penetration levels, six different phases have been defined ranging from no impact to severe impact from VRE. Sri Lanka with its currently envisaged development of solar and wind is expected to move all the way from the beginning of phase 2 to the end of phase 6 within 10 years. This signifies the planned transition of the country as well as the scale of challenges the country should address in this pathway.

10.8 Renewable Energy Curtailments

Although all renewable energy power plants shall operate on must run condition, curtailment of renewable energy resources can occur due to transmission congestion or excess generation during low demand periods. The excess generation mainly occurs due to the seasonality effects of VRE generation, being incompatible with the demand. The excess energy produced during certain time periods has to be curtailed to maintain system frequency. As the penetration of variable renewable energy sources increases, the capability to absorb all the VRE produced also decreases. The oversupply of VRE generation can be solved to a certain extent from storage solutions, however it cannot be completely mitigated.

The severity of renewable energy curtailments of the Base Case scenario can be observed throughout the time horizon as illustrated in Figure 10.11.

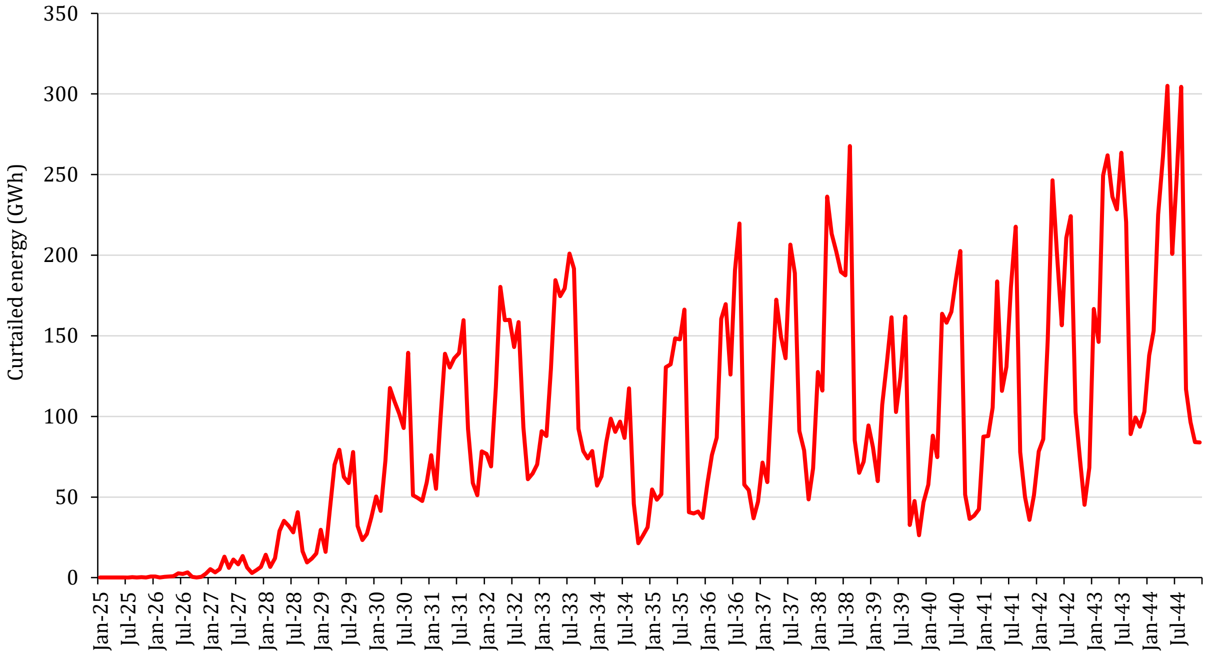


Figure 10.11 - Monthly Renewable Energy Curtailments

Even though minor scale renewable energy curtailments can be observed from 2025 onwards, the curtailments become distinct only after 2028. The introduction of large-scale Battery Energy storage devices to the system from 2028 onwards is essential to avoid further curtailments than depicted. With the introduction of pumped storage hydro power plants, the curtailments reduce to a certain extent from year 2034 onwards. The introduction of 500 MW interconnection with India allows to further reduce the curtailments from year 2039 onwards as shown in Figure 10.11. However, as the share of VRE sources increase rapidly, the renewable energy curtailments tend to rise throughout the planning horizon. Additional interventions beyond conventional storage solutions are required to mitigate this curtailment of surplus energy.

Table 10.5 depicts the magnitude of renewable energy curtailments observed in each year for the planning horizon from 2025 to 2044.

Table 10.5 - Renewable Energy Curtailments

Year	Maximum Observed Curtailment Event (MW)	Average Annual Total Curtailment (GWh)	Curtailment Share			
			From Total Generation (%)	From ORE Generation (%)	From Dispatchable Solar Projects (%)	From Dispatchable Wind Projects (%)
2025	491	2	0.0%	0.0%	1%	0%
2026	682	14	0.1%	0.2%	1%	1%
2027	913	85	0.4%	1.2%	6%	2%
2028	1,294	250	1.2%	2.7%	10%	5%
2029	1,727	557	2.5%	5.2%	16%	8%
2030	2,461	933	3.9%	7.7%	22%	11%
2031	2,450	1,214	4.8%	9.1%	26%	12%
2032	2,744	1,354	5.1%	9.3%	26%	12%
2033	3,211	1,562	5.6%	10.0%	27%	13%
2034	3,319	818	2.8%	4.9%	12%	7%
2035	3,330	1,038	3.4%	5.8%	14%	9%
2036	3,678	1,284	4.0%	6.8%	15%	10%
2037	4,249	1,386	4.1%	6.9%	16%	10%
2038	4,405	1,857	5.1%	8.7%	19%	12%
2039	3,751	1,084	2.9%	4.8%	10%	7%
2040	4,370	1,263	3.2%	5.4%	11%	8%
2041	4,094	1,324	3.2%	5.5%	12%	7%
2042	4,470	1,638	3.8%	6.4%	13%	9%
2043	5,516	2,158	4.7%	7.8%	16%	10%
2044	6,049	2,218	4.6%	7.8%	16%	10%

It is to be noted that the above values are based on the assumption, that at least 90% of the future grid connected solar projects and all wind projects are dispatchable. If the grid connected solar development is to be replaced with distribution embedded solar projects, they are required to provide grid support services with capabilities of remote curtailment.

It is also mandatory to establish renewable energy curtailment rules in the grid code, such that downward adjustment of power sources is facilitated in a transparent manner. The conditions related to curtailment is required to be mandated in relevant power purchase agreements appropriately.

Establishment of the Renewable Energy Control Centre and associated infrastructure at National System Control Center with tools for monitoring, controlling, scheduling and forecasting renewable energy resources is critical for this requirement. Curtailments can be practiced through online and offline modes. During offline mode, where remote controlling is not possible, curtailments are done on day ahead instructions based on weather forecasts. However, in such instances curtailments can be excessive, because of the prediction error. On the other hand, in online mode where remote controlling and monitoring is enabled, it is possible to curtail the amount that is exactly required corresponding to the actual demand. Furthermore, it is required to transparently allocate the renewable energy curtailment requirement among different renewable energy power plants automatically through the curtailment scheduling platform at the Renewable Energy Control Centre. For these salient features of the curtailment policy shall be considered as applicable in each PPA and variables such as curtailment cost, generation cost, maximum and allowable non compensable curtailment, minimum annual/ monthly generation, transmission network congestion management has to be considered

The renewable energy curtailment results in varying hydro conditions for policy target year of 2030 illustrates a curtailment level of 820-1,100 GWh per year. This shall increase to a range of 1,900-2,800 GWh in year 2044. The average daily curtailment pattern and average weekly curtailment pattern of year 2044 are illustrated in Figure 10.12.

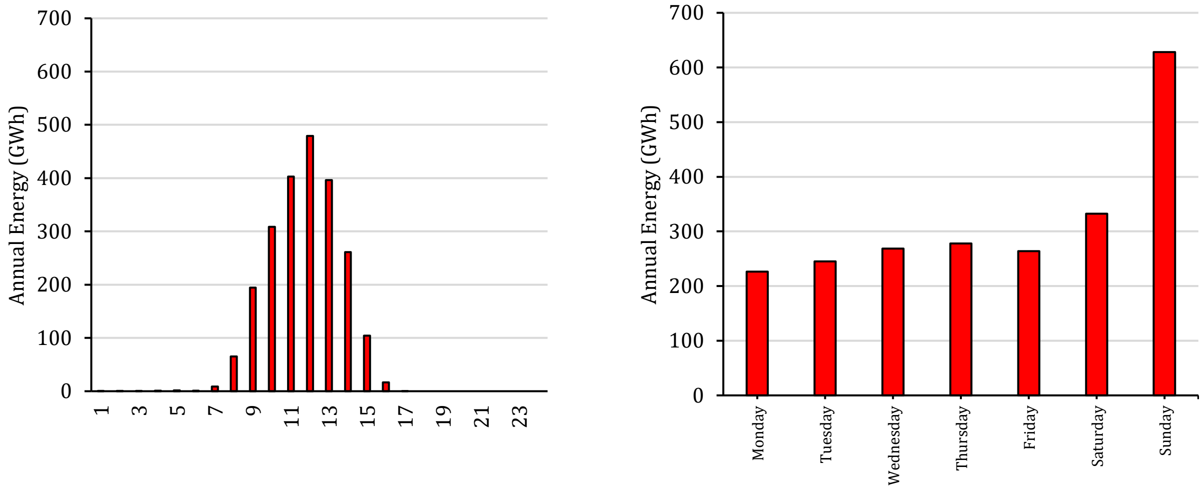


Figure 10.12 - Daily Curtailment Pattern and Average Weekly Curtailment

The major observations on curtailment pattern are as follows.

1. Curtailment during the dry season (January to April) is relatively low and occurs mainly during daytime in Sundays, where the demand is comparatively low.
2. Highest Curtailment during the year is observed during the High Wind Season (May-September). The curtailment is mostly during daytime in which solar production and wind production overlap. There can be occasional curtailments during off-peak times during this season where wind production is very high. Curtailment can be observed in both weekdays and weekends.
3. Curtailment during the wet season (October-December) is also relatively low with curtailment mainly observed during daytime in Sundays, where demand is comparatively low.

10.9 Operation of Energy Storage

The battery energy storage and pumped hydro storage are integral developments for the future power system which provide the most essential services to keep the system running. The services of providing frequency regulation and energy shifting are the most critical aspects identified in the generation planning studies and the storage systems are expected to provide these services. Even though, both storage services provide similar services, each has unique characteristics which are essential to complement the requirements of the power system.

10.9.1 Battery Energy Storage

The proposed battery energy storage shall possess multiple functionalities. One hour duration batteries are proposed for frequency regulation, fast frequency response and system restoration purposes. The four hour duration BESS are primarily proposed for energy shifting while assisting fast frequency response services during contingencies. All battery energy storage systems shall have the capability to operate as per the dispatch instructions from the National System Control Centre.

The round trip efficiency of battery energy storage is above 80%. However, the number of life cycles are dependent on depth of discharge. During simulations the depth of discharge is considered at 80% dedicated for energy shifting purposes. However, the remaining storage can be utilized for fast frequency response services during any contingency event. The annual utilization factor for energy shifting purposes shall be around 26%. The daily operation pattern and monthly utilization of the energy shifting function of battery energy storage systems in year 2044 is illustrated in Figure 10.13.

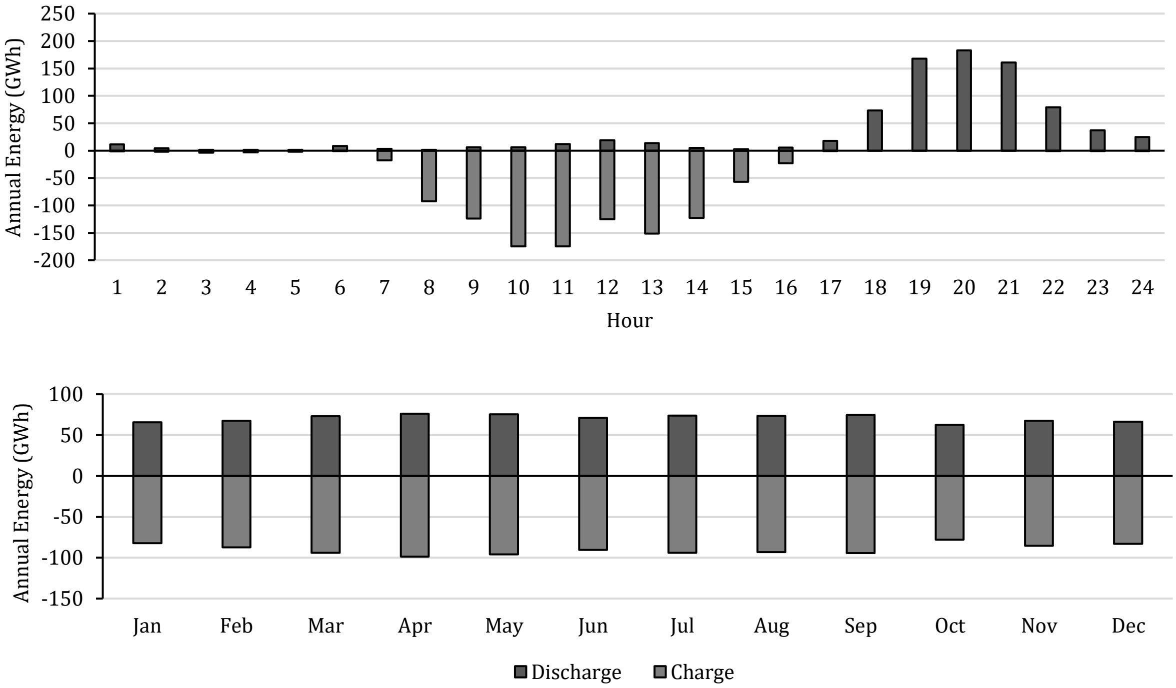


Figure 10.13 - Daily Operation and Monthly Utilization of Battery Energy Storage

10.9.2 Pumped Hydro Storage

The proposed pumped hydro storage shall consist of three 200 MW constant speed units. Since Battery energy storage units are expected to be operated with fast frequency services, pumped storage units shall be developed as constant speed units to provide necessary synchronous inertia to limit the Rate of Change of Frequency (ROCOF). Hence frequency related services during pumping operation are not possible. The main functionality of pumped hydro storage shall be for energy shifting and inertia services.

The storage duration of pumped hydro storage is designed for six hours. The round trip efficiency of pumped hydro storage is approximately 70%, which is in contrast lower than battery energy storage systems. However, considering the very long lifetime capability of pumped hydro storage in comparison to the life cycle limitation of battery energy storage operational pattern of the storage assets could be altered. The annual utilization factor of pumped hydro storage units shall be around 52%. The daily operation pattern and monthly utilization of the pumped hydro storage systems in year 2044 is illustrated in Figure 10.14

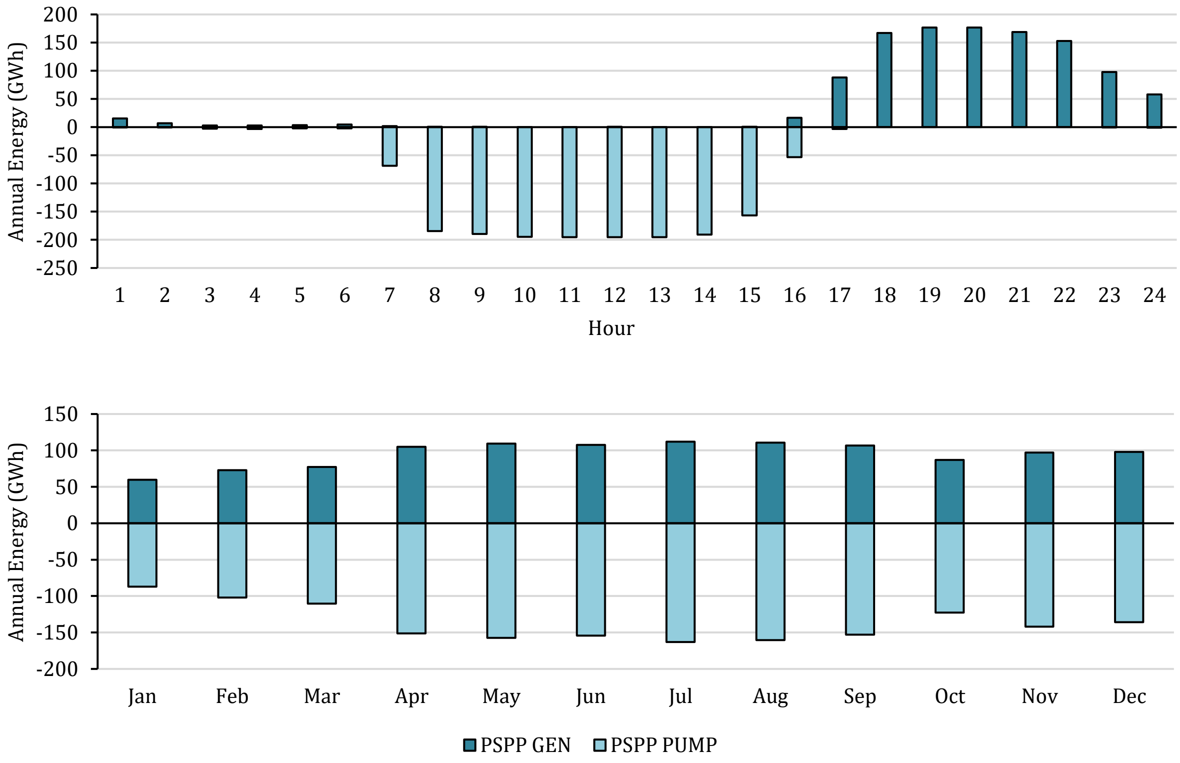


Figure 10.14 - Daily Operation and Monthly Utilization of Pumped Hydro Storage

10.10 Operation of Interconnection

The development of Interconnection allows Sri Lanka to import electricity through long term bilateral contracts or the Day Ahead Market (DAM). It also allows to export electricity to earn revenue, during the periods of surplus generation. Hence the renewable energy curtailments are significantly reduced after the interconnection is established.

However, in order to allows free power transfer between the two countries, the Interconnection capital cost should be unbundled from the handling charge and considered as a fixed annuity or monthly payment. Hence, the power transfer is based on the load marginal cost of Sri Lanka and the marginal cost of India DAM. Figure 10.15 illustrates the average hourly load marginal cost of Sri Lanka and India DAM in year 2040.

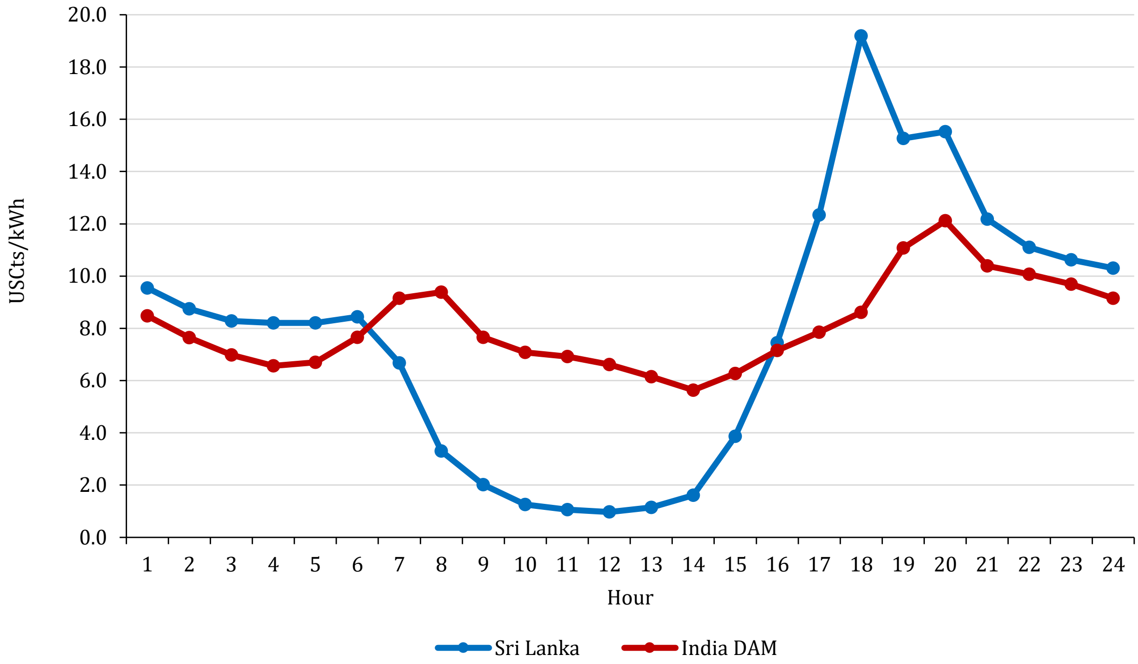


Figure 10.15 - Marginal Cost for Trading between Sri Lanka and India

The annual utilization factor of Interconnection is tabulated in Table 10.6. The daily operation pattern and monthly utilization of the Interconnection in year 2044 is illustrated in Figure 10.16.

Table 10.6 - Utilization Factor of the Interconnection

Year	Energy Imported to Sri Lanka (GWh)	Energy Exported to India (GWh)	Utilization Factor
2039	2,104	788	66%
2040	2,176	775	67%
2041	2,399	812	73%
2042	2,398	871	75%
2043	2,254	982	74%
2044	2,323	947	75%

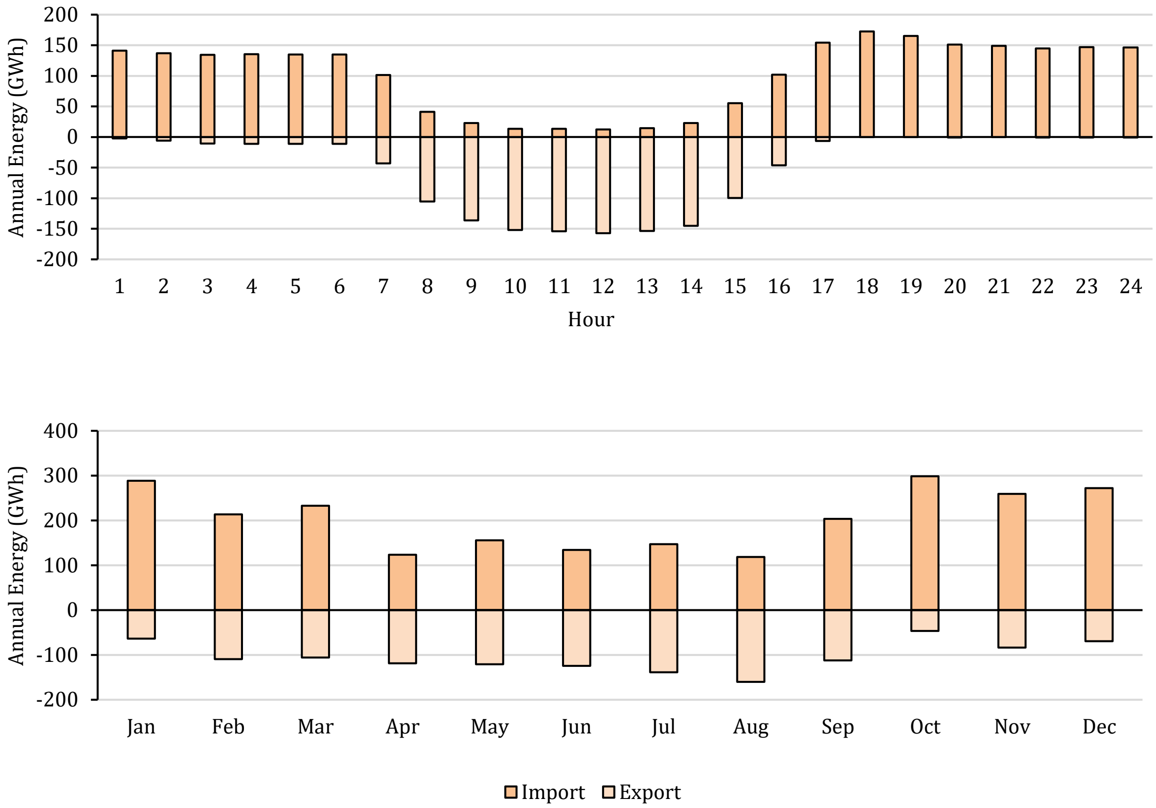


Figure 10.16 - Daily Operation and Monthly Utilization of Interconnection

The exports are mainly dominant during daytime, while imports are observed during all the remaining hours. The imports are reduced during the high wind season, as the low cost renewable energy generation is available throughout the day.

However, it is important to note that simulations have been conducted based on present conditions of DAM in India. The export revenue is dependent on the market clearing price of the DAM. In future due to the anticipated aggressive renewable energy deployment in India, the daytime DAM prices could further decrease. This could have an impact on the revenue and volume of exports from Sri Lanka during the daytime hours.

Furthermore, the import pattern may have minor deviations if bilateral contracts are made with take or pay clauses. The simulations only give guidance on a possible scenario, and exact implications should be assessed with the contractual terms associated with the interconnection and associated generation companies.

10.11 Operations of Thermal Power Plants

The performance patterns of thermal power plants are altered significantly with the rapidly rising VRE Generation. Conventional operating patterns from base load to peak load operation of the thermal power plants have to be adjusted for more flexible operating patterns. The key features of high ramping capabilities, lower minimum load operating capability, higher number of start stop cycles, lower uptime and downtime requirements are essential requirements for thermal power plants operating in a high VRE system. However, limited capacity from coal, combined cycle or nuclear power plants shall continue to operate on baseload function. with capabilities to deload to minimum operation when required.

The combined cycle power plants are expected to operate primarily with daily cycling during the period from 2026 to 2035. This means that the plants will have to start and stop daily during most periods of the year. This is mainly due to the increased penetration from solar power during the daytime, which creates the 'duck curve' in net demand. However, from 2035 onwards, these plants are projected to transition to predominant base load operation, where they will run continuously at a consistent output level to meet the steady demand for electricity. It can be observed that the operation of combined cycle power plants is mainly during the dry season and wet season of each year.

The more flexible thermal generation sources such as gas engines operate throughout the year. They will operate as intermediate cyclic load operation with high number of start stops to facilitate the variations. One of the key advantages of gas engines is their operational flexibility. They can start up quickly, adjust their output rapidly, and shut down efficiently, making them well-suited for environments where demand varies significantly throughout the day. This flexibility is crucial for integrating variable renewable energy sources, like wind and solar, which can cause sudden changes in power generation due to their intermittent nature. The aero derivate gas turbine technology also allows similar level of flexibility though fast start and ramping capabilities. This makes them ideal for applications where speed and agility are essential, such as in balancing the grid during peak demand periods or compensating for sudden drops in renewable energy production.

Heavy duty gas turbine power plants are primarily intended to operate as peaking power plants, providing electricity during critical night periods. However, considering their high inertia capabilities they can also be utilized for dual-purpose functions, allowing the generator to decouple from the turbine using a clutch. In this configuration, the generator can operate as a synchronous condenser, enhancing grid stability and providing reactive power support.

The annual plant factor variation of main thermal technologies during the planning horizon is depicted in Figure 10.17. The expected annual start stop cycles of main thermal technologies during the planning horizon as observed during hourly simulation studies is illustrated in Figure 10.18. It is to be noted that the actual start stops can further increase during actual intra hour operation of the power system.

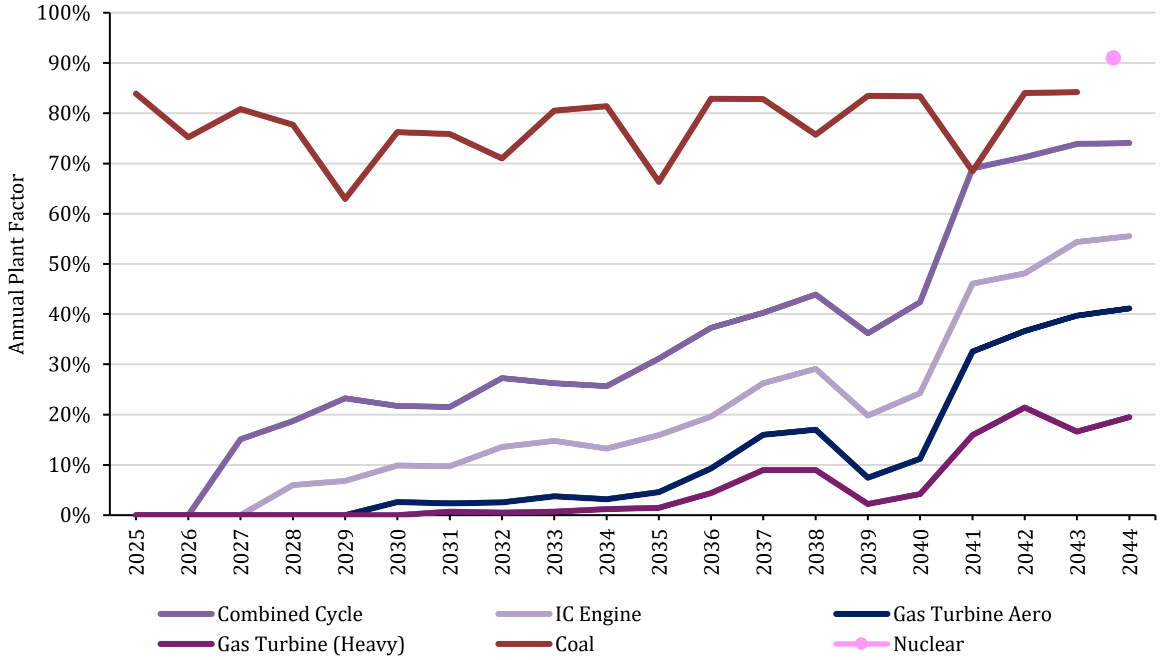


Figure 10.17 - Plant Factors of Thermal Technologies

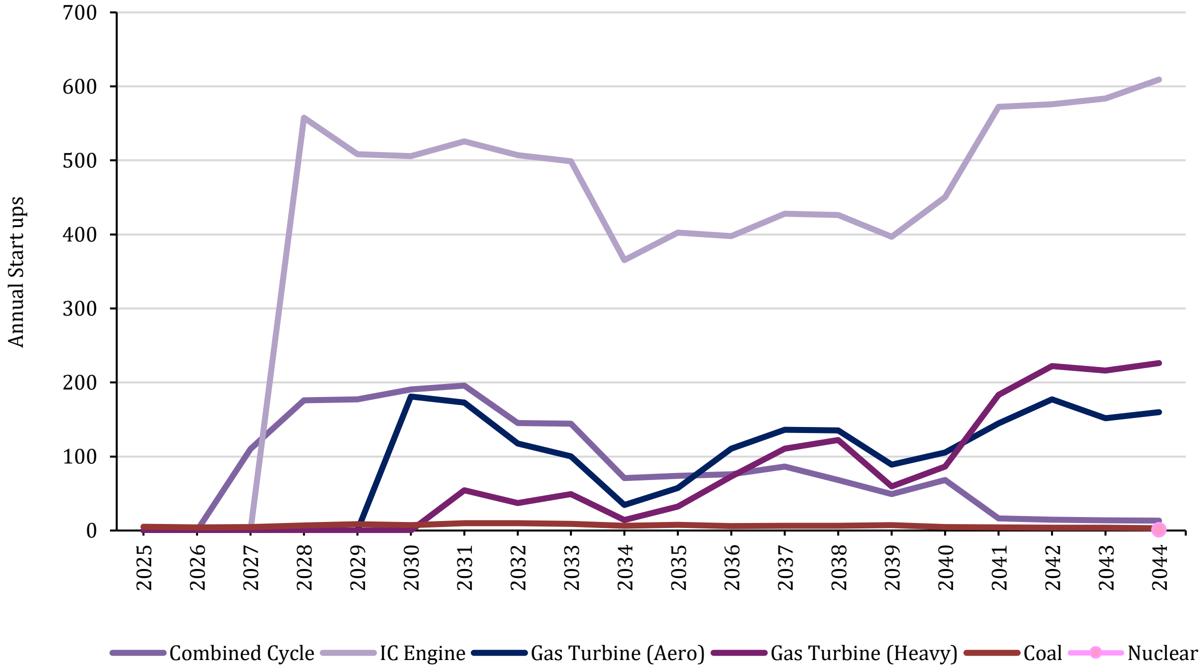


Figure 10.18 - Start-ups of Thermal Technologies

The detailed operation of thermal power plants under different renewable generation conditions (low, average and high RE) are provided in Annex 10.3

10.12 Fuel, Operation and Maintenance Requirement

Expected expenditure on fuel and operation & maintenance (variable O&M and fixed O&M) for Base Case scenario from 2025 to 2044 is summarized in five-year periods in Table 10.7

Table 10.7 - Fuel Cost and Operation & Maintenance Cost

Year	Operation and Maintenance Cost							Fuel
	Hydro	Thermal	PSPP	BESS	ORE	Interconnection	Total O&M	
2025-2029	199	587	-	2	392	-	1,181	2,772
2030-2034	199	602	8	14	746	-	1,569	2,343
2035-2039	199	648	41	20	1,018	26	1,952	3,097
2040-2044	199	1,041	41	22	1,342	128	2,773	4,402
Total	**796**	**2,878**	**90**	**59**	**3,499**	**154**	**7,474**	**12,613**

Total O&M cost in constant terms for the horizon is USD 7,474 million while the fuel cost is USD 12,613 million in constant terms. The increase in O&M cost down the horizon can be mainly attributed to the addition of ORE plants, flexible thermal plants and storage systems with the continuously increasing demand.

The Quantity of annual fuel requirement is shown in Figure 10.19 and cost incurred for fuel is indicated in Figure 10.20. Detailed information about annual fuel requirement both quantity-wise and cost-wise is presented in Annex 10.7.

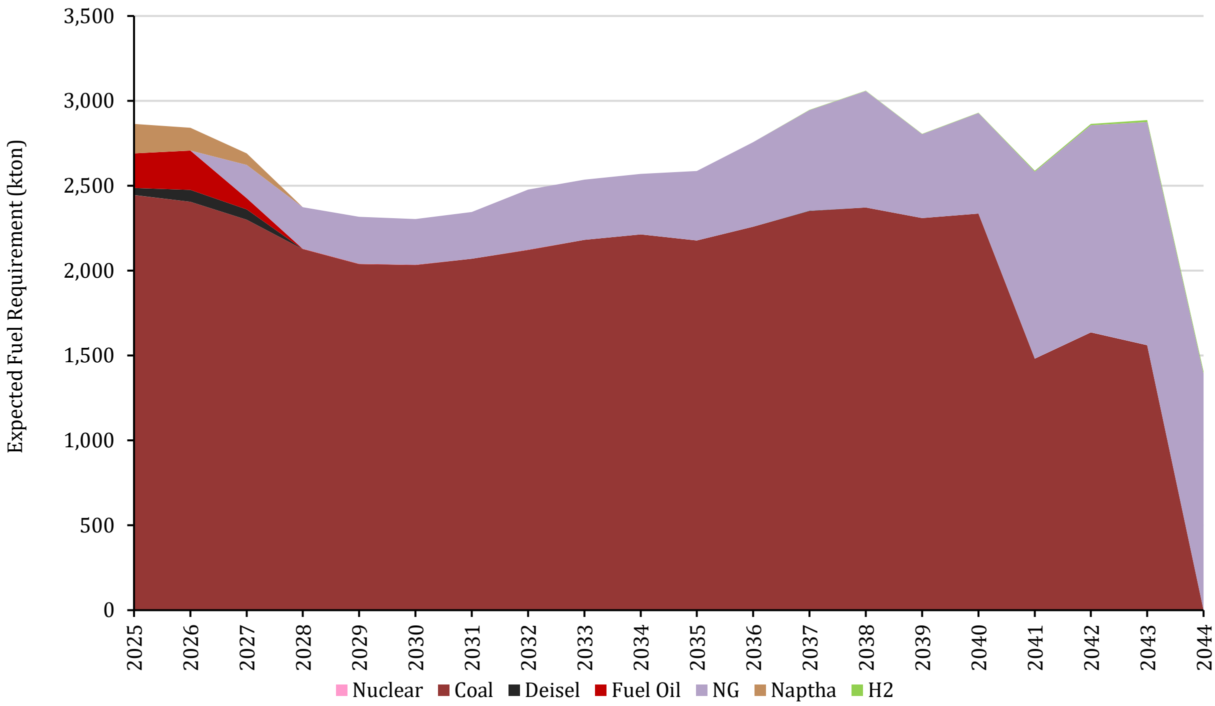


Figure 10.19 –Category wise Fuel Requirement

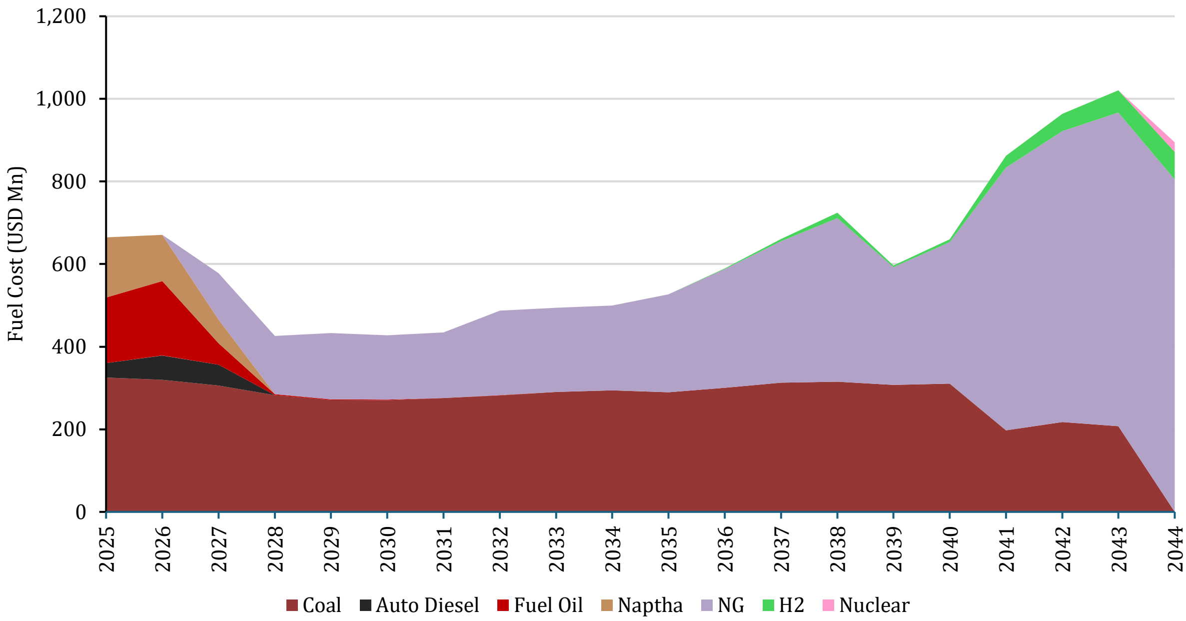


Figure 10.20 – Category wise Fuel Cost

In the initial years of the planning horizon oil requirement is relatively high and it becomes negligible after 2027 with the introduction of NG together with conversion of major oil-fired plants to natural gas. Naphtha, FO and Diesel are eliminated from the system gradually. It should be noted that if LNG supply is further delayed, plants will continue to operate with their present fuels until the LNG supply is made available. Coal is the dominant fuel accounting for more than 80% of total fuel requirement up to 2036 and subsequently phases out after the retirement of coal power plant by 2043. From 2027, being the only clean fuel to power firm thermal capacities, natural gas requirement fairly increases at an average rate of 14% with the addition of more flexible thermal power plants to the system. It should also be highlighted that from 2035 onwards hydrogen blended natural gas are considered as the fuel for thermal plants additions. Hence during 2035 – 2038 natural gas demand continues to increase and hydrogen is also introduced to the fuel mix. In 2039 with the addition of HVDC interconnection natural gas requirement drops but bounces back with the initiation of unit wise retirement of the coal power plant. Due to the minimal dispatch of power plants operated on hydrogen blended natural gas, and the fact that hydrogen is blended only up to 30% by volume, the requirement of hydrogen fuel also remains low. In 2044, total fuel requirement arising from nuclear fuel is less than 0.001%, even though 10% of the energy is generated through the plant owing to its high energy density.

Natural gas requirement over the horizon for low, average and high renewable energy scenarios is illustrated in Figure 10.21.

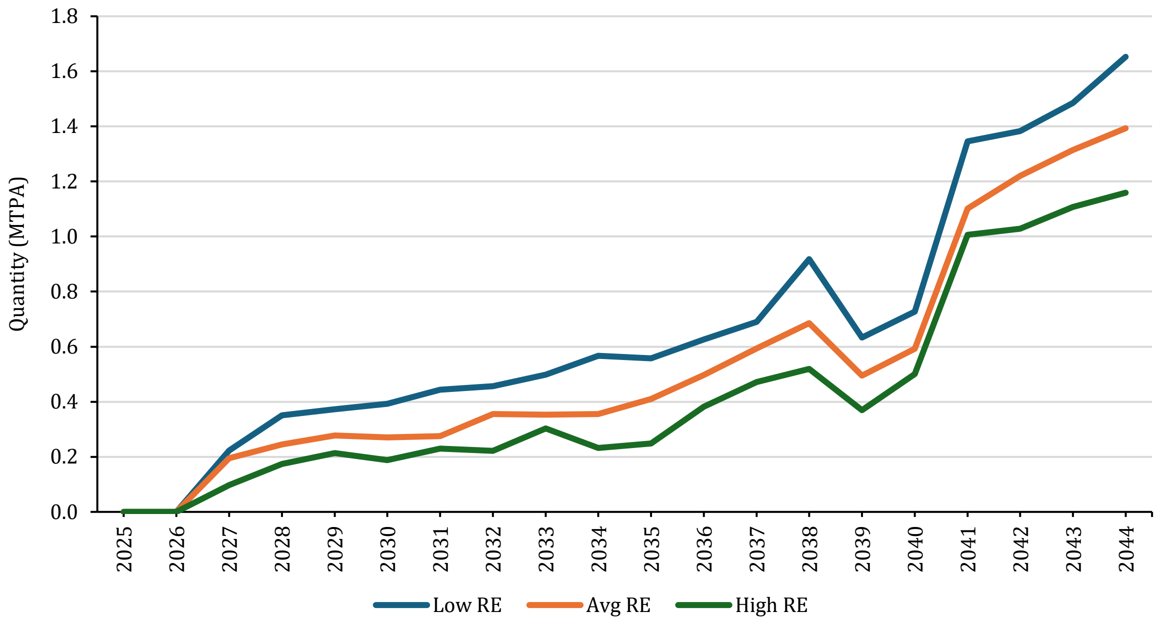


Figure 10.21 - Expected Annual Natural Gas Requirement

10.13 Marginal Cost Patterns

The load marginal cost in an electricity system refers to the additional cost incurred to produce one more unit of electricity. It is a crucial concept in the economics of electricity markets and helps in understanding the pricing and production decisions. Figure 10.22 illustrates the annual average of hourly load marginal cost of selected years in the planning horizon.

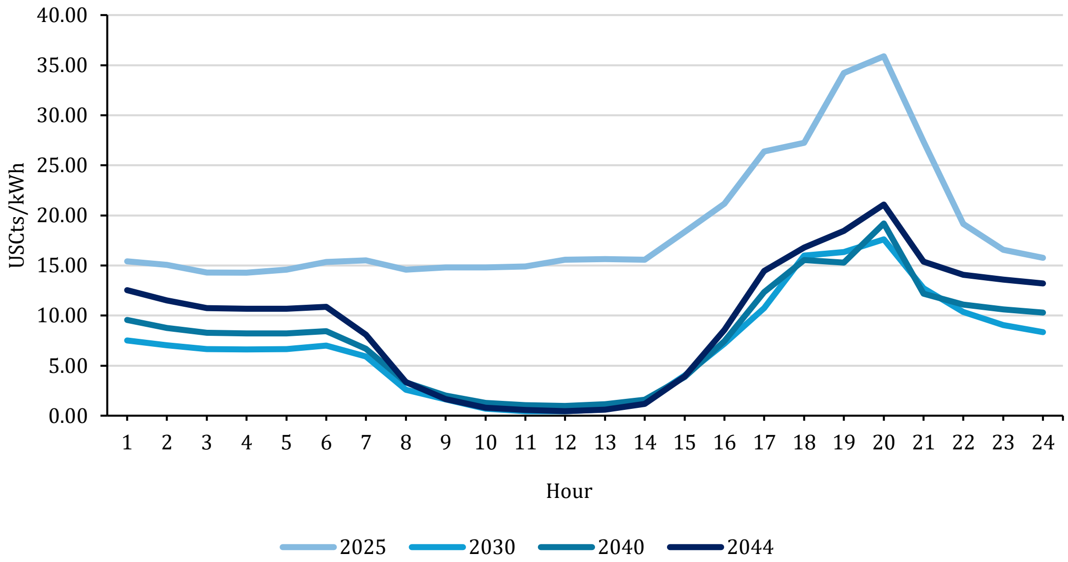


Figure 10.22 - Annual Average of Hourly Load Marginal Cost

It is noted with the high penetration of solar, the marginal cost of electricity during daytime becomes minimal as early as 2029. Hence capacity additions beyond 2030, require to consider the annual day time demand increase as well as integration of storage solutions.

10.14 Ramping and Reserve Requirements

In order to operate the power system stably and reliably, necessary ancillary services are required. These have different functionalities and different purposes than providing electricity in merit order. Having appropriate capacity of these ancillary services is mandatory to operate the power system safely and securely. In power system operations, reserves are categorized based on their response time and purpose into primary, secondary, and tertiary responses. Each type plays a crucial role in maintaining grid stability and reliability. The typical response requirements to operate power system and their characteristics are graphically illustrated in Figure 10.23.

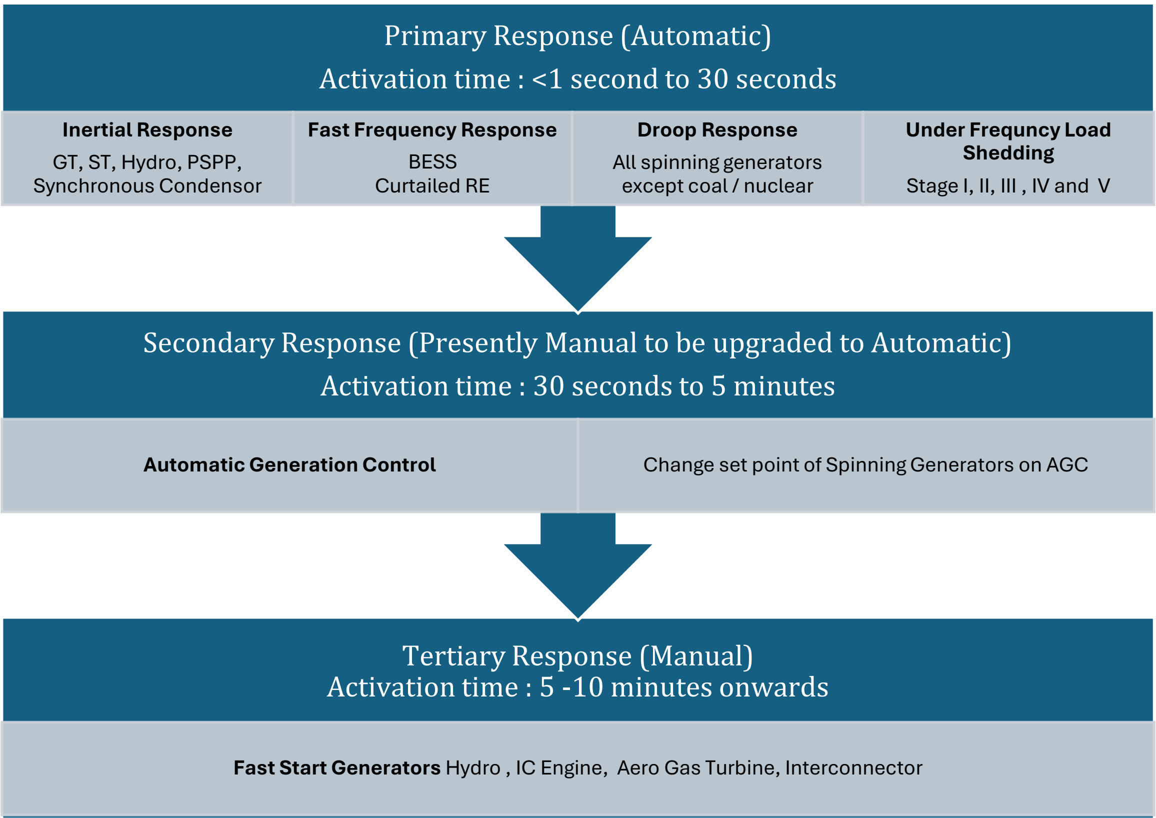


Figure 10.23 - Types of Operating Reserves

Primary Response

Primary Reserves are the first line of defense against sudden imbalances between supply and demand. They are used to stabilize the frequency of the power system immediately after a disturbance, such as the sudden loss of a generator. Activation typically occurs within seconds (up to 30 seconds) after a frequency deviation is detected. Primary reserves are automatically and rapidly deployed by frequency-responsive generators and loads to arrest the frequency deviation and prevent it from escalating. The types of primary reserves based on their activation time and characteristics can be classified as follows.

1. Inertial Response

   Inertial response refers to the natural, immediate reaction of large rotating masses to changes in the system's frequency. This response occurs without the need for any control systems or external commands and plays a critical role in stabilizing the grid following sudden disturbances. Heavy duty gas turbines, steam turbines, hydro generators, pumped hydro power plants have high inertia capabilities. However, to provide the inertia services power plants are required to be online with generation. Synchronous condensers are presently repurposed to provide the same service and can be used to provide inertial response.

2. Droop Response

   All generators including grid connected solar and wind projects are expected to operate on droop mode with free governor action. Droop response shall provide active power proportionally to the frequency change and is used to mitigate expected frequency changes. Droop control is automatic and shall be set to setting between 2-9%. The activation time period can be within few seconds to 30 seconds. In order to provide droop response, significant amount of capacity needed to be considered for spinning reserves. In Sri Lanka a minimum of 5% spinning reserve is usually been kept considering demand fluctuations. However, considering the variations of renewable energy dynamic probabilistic reserves (DPR) are incorporated to increase the system spinning reserves up to 20% during certain periods.

3. Fast Frequency Response

   Fast Frequency Response services should be active within less than a second. There are frequency deadband such that they will operate only for critical contingency events of higher ROCOF or higher frequency drop or rise. All Battery Energy Storage projects identified in the planning studies are required to have FFR capabilities, and dispatchable solar and wind projects which are on curtailment mode can also be procured to provide the same service. FFR services will only operate with a given frequency dead band, hence shall not trigger an automatic response in small deviations in frequency.

4. Under Frequency Load Shedding

   Under Frequency load shedding is a protection scheme deployed as the last resort to prevent complete system failure. Presently UFLS is deployed in five stages depending on the severity of frequency drop and frequency drop rate. 42.5% of demand rejection is deployed based on frequency drop and 18% demand rejection is deployed based on ROCOF.

   - UFLS stage 1 operates at 48.75 Hz in period of 100ms to reject a demand of 7.5%.
   - UFLS stage II operates at 48.5 Hz in period of 500ms to further reject an additional demand of 7.5%.
   - UFLS stage III operates at 48.25 Hz in period of 500ms to further reject an additional demand of 11%.
   - UFLS stage IV operates at 48.00 Hz in period of 500ms to further reject an additional demand of 11%.
   - UFLS stage V operates at 47.5Hz instantaneously to further reject an additional demand of 5.5%
   - If frequency drop is below 49 Hz and ROCOF higher than 0.85 Hz/ Second demand of 18% is rejected.

Secondary Response

Secondary reserves are used to restore the system frequency to its nominal value and to relieve primary reserves, which have been activated initially. They help in maintaining system stability and ensure that the primary reserves are ready for any subsequent disturbances. Activation usually occurs within 1 minute and expected to provide at least for 5 minutes after the initial disturbance. Secondary reserves are managed by the system operator and can include both automatic and manual adjustments. Presently this is done manually by Victoria power station or Kotmale power station. Since secondary reserves must be able to respond quickly, they are required to be converted to automatic generation control (AGC) systems with higher fleet of power plants capable of providing this service. The present practice on dependance on a single generator unit for secondary reserves requires to be enhanced to AGC mode with upgrading the systems of generator units. If the available spinning reserves are inadequate, secondary reserves can be provided by non spinning reserves such as IC engines, provided their auxiliary systems are already in operation.

Tertiary Response

Tertiary reserves, also known as replacement reserves, is a response in a power system that are activated to restore the system's balance after the primary and secondary reserves have been deployed. Their primary purpose is to ensure that the power system has sufficient reserves available to handle further disturbances and to replace the reserves that have already been used. Typically, generators that can be started within 10 minutes can supply this service requirement. Hydro generators, IC engines and Aero derivative gas turbines shall provide these services.

The expected capacities identified in the Base Case scenario to provide such services are depicted in Table 10.8 for selected years.

Table 10.8 - Reserve Requirements

Year	Inertial Response	Fast Frequency Response	Secondary Reserves	Tertiary Reserves
2025	Spinning Generators	None	Victoria, Kotmale	Hydro
2030	Spinning Generators Synchronous condensers	BESS – 350 MW	Spinning Generators on AGC	Hydro IC Engine 200 MW Aero GT -130 MW
2035	Spinning Generators Pumped Hydro Storage, Synchronous condensers	BESS – 750 MW	Spinning Generators on AGC	Hydro IC Engine 200 MW Aero GT -130 MW
2040	Spinning Generators Pumped Hydro Storage, Synchronous condensers	BESS – 850 MW Curtailed RE	Spinning Generators on AGC	Hydro IC Engine 400 MW Aero GT -130 MW HVDC Interconnector
2044	Spinning Generators Pumped Hydro Storage, Synchronous condensers	BESS – 900 MW Curtailed RE	Spinning Generators on AGC	Hydro IC Engine 600 MW Aero GT -130 MW HVDC Interconnector

The daily ramp up events of large magnitude of VRE generation is mainly caused by the rise in solar PV generation in the morning half of the day and ramp down events at the evening portion. The cumulative VRE ramp in hourly resolution during morning and evening is much lower in high wind season and wet season, due to the capability of utilizing wind during sunrise and sunset periods. However, further extensive studies are required in intra hourly time scale to depict the effect of VRE variations.

The effect of ramping events considering changes in both VRE generation and demand change have to be addressed by the system operator. These large changes take place in the evening reflecting the "Duck Curve" effect for the net demand requiring the ramping up of flexible generation to meet the sharp evening peak appearing in the net demand. Since this is much of a predictable situation, system operator can plan ahead by having sufficient power plants capable of ramping during that time. The three hour daily ramp event of the net demand can reach up to 2,000 MW in the year 2030 requires the operation of peaking capacities. The flexible capacity required to adjust the output to maintain the supply demand balance in the hour-to-hour basis can reach up to 1,000 MW by 2030. The Figure 10.24 illustrates the pattern, hourly ramp requirements and variation in three hour periods of the net demand in a sample week of year 2030.

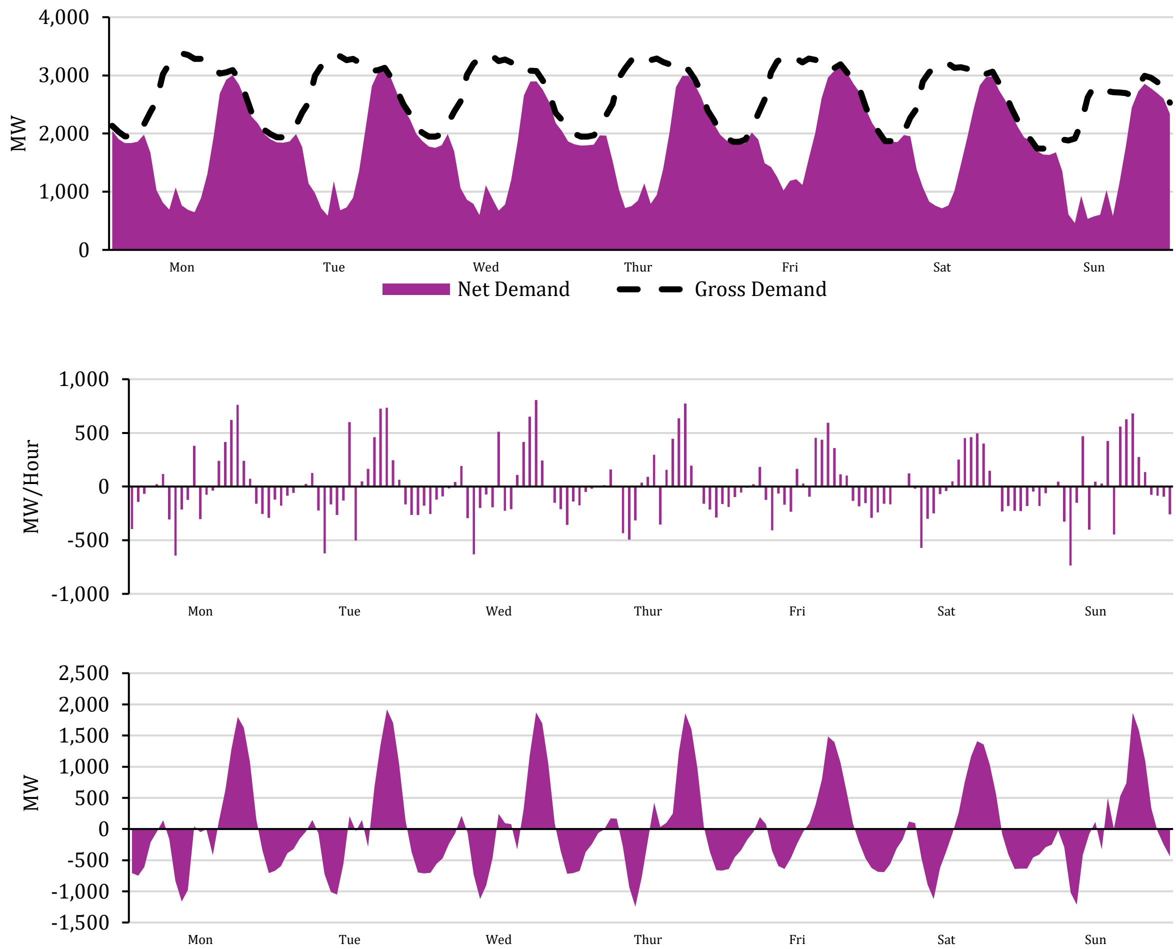


Figure 10.24 - Net Demand Variation Requirements

The intra hour ramp requirements, the hourly ramp requirements and three hour ramp requirements and the possible technologies to provide such services as identified in planning studies is illustrated in Figure 10.25.

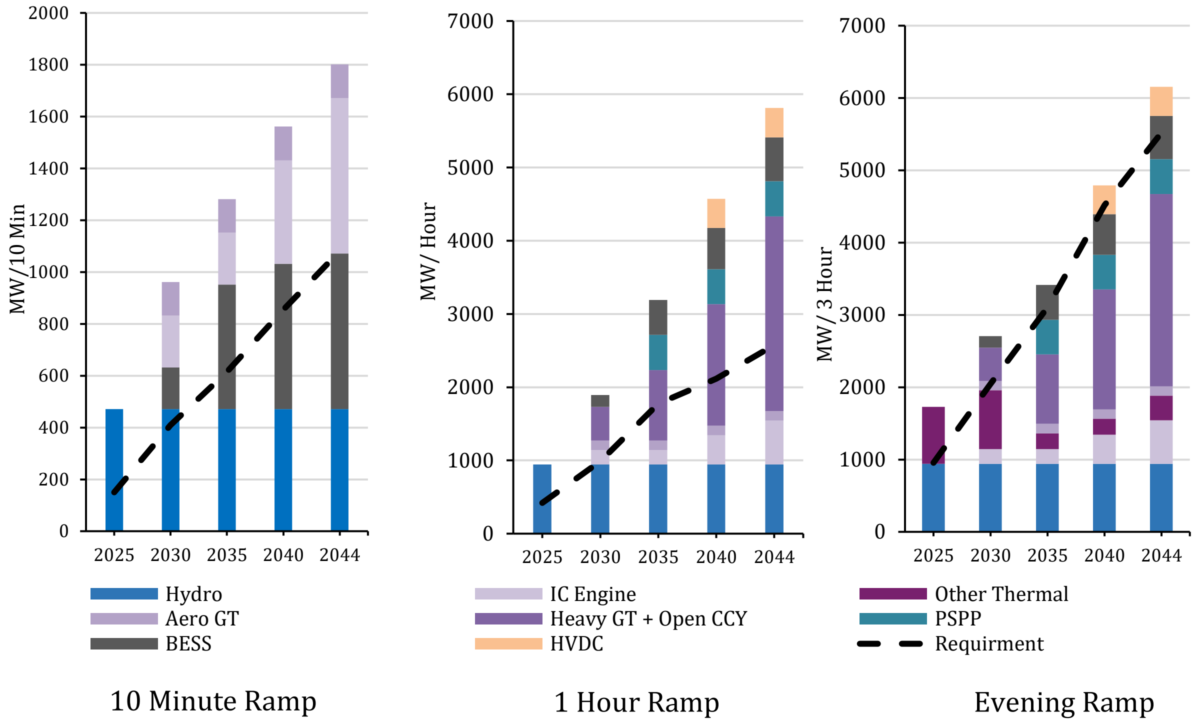


Figure 10.25 - Ramp Requirements for the Power System

The 10 minute ramp rates are based on satalite data of geographically scatterd renewable projects and variations of approximatley 100 MW can be observed within this period in year 2025. Presently such variations can only be succesfully absorbed by hydro generators avaialble in the system. This requirement shall gradually increase upto 1,000 MW by year 2044, and introduction of battery energy storage with IC engines and aero derivative gas turbines are expected to mitigate such variations in the net demand.

The hourly ramp events can occur anytime during the day and necessary technologies are required to address such variations. These variations can start from 400 MW in year 2025 and progress up to 2,500 MW by year 2044. The available hydro capacity shall be energy limited for such regulation purposes due to the muti purpose requirements of water resources. The battery energy resources are the fastest to respond to such requirements, however are limited with the energy capacity for prolonged periods. In such instances IC engines , aero derivative gas turbines , heavy duty gas turbines shall provide sufficnent ramping capabilities to the system. The development of PSPP and Interconnection shall also provide necessary support for ramping requirments during the next decade.

The evening ramp on the other hand is a predictable event for the system opertor with proper day ahead planning. These events can grow from 1,000 MW in year 2025 upto 5,500 MW by year 2044. Sufficent capacity is required to be procured as illustrated in Figure 10.25 to prepare for the chanllenging evening ramp condictions.

10.15 Reliability Assessment

Planning studies have been conducted in compliance with the reliability criterion depicted in "The technical and reliability requirements of electricity network of Sri Lanka" which was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL. In accordance Base Case scenario has met following criteria

a) Maintains the firm capacity share within the minimum reserve margin of 2.5% and maximum reserve margin of 20% at the critical period for each year. Critical period is generally considered as the month with the driest hydro condition. Reserve Capacity in the worst hydro condition is maintained within the stipulated limits even during the first half of the planning period despite the retirement of several thermal power plants in this period.
b) Maintains the annual Loss of Load Probability (LOLP) value below the maximum LOLP value of 1.5%, which should be complied during all conditions including the driest hydro conditions

The planning reserve margin for the critical periods for the 20-year period, considering the available firm capacity is shown in the Figure 10.26

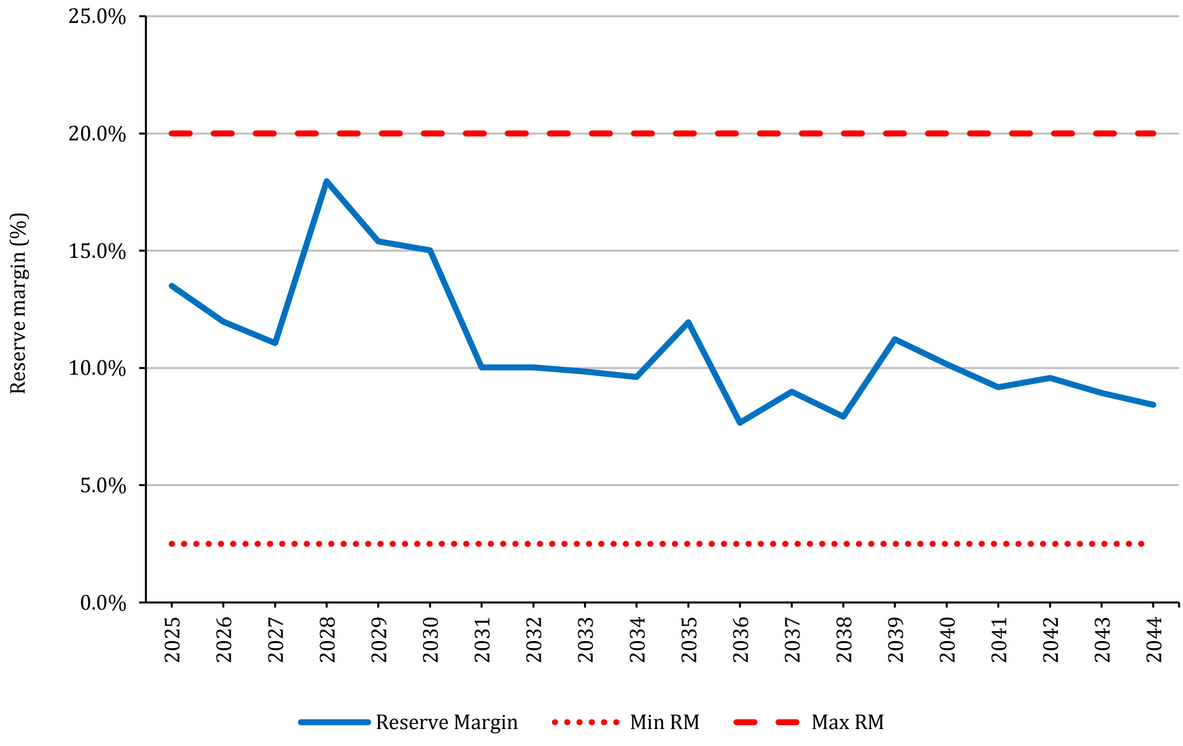


Figure 10.26 - Variation of Reserve Margin

The Loss of Load Probability for the planning horizon, is illustrated in the Figure 10.27

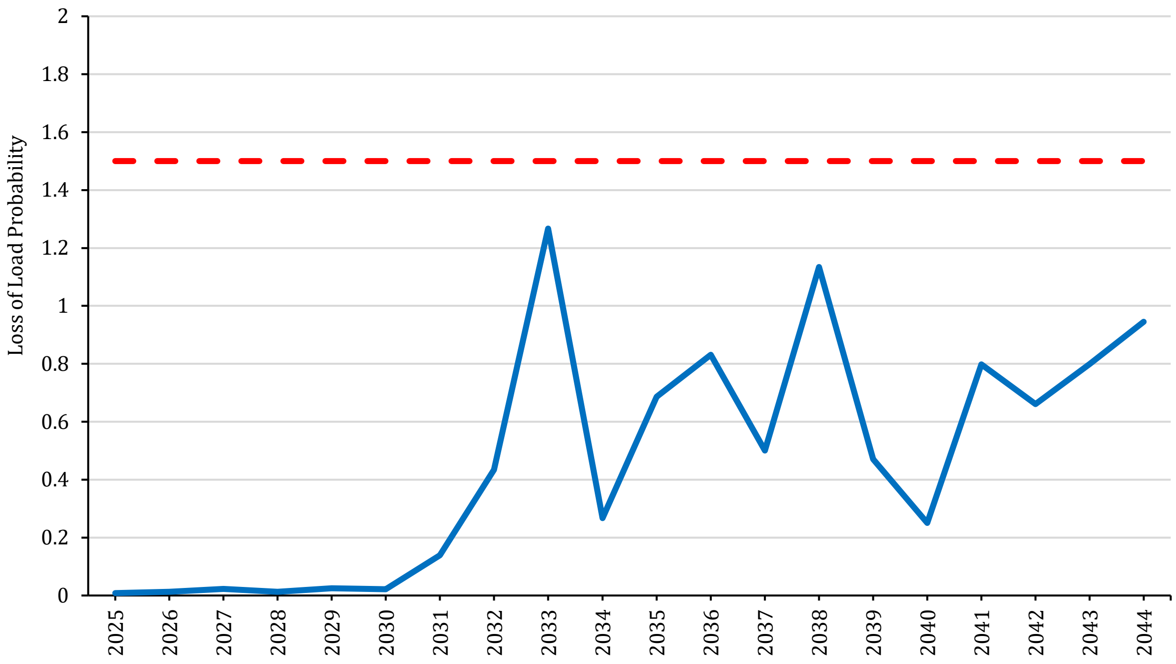


Figure 10.27 - Variation of LOLP

Both planning reserve margin and LOLP are within stipulated limits of reliability criteria published by the regulator. Since Sri Lanka is progressing more towards integrating a higher share from weather dependent VRE sources, calculation of other matrices to assess resource adequacy is necessary. Hence other resource adequacy checks are required to be deployed to ensure sufficient reliability during critical periods. Since significant share of solar energy is introduced, there is sufficient capacity to meet the day time peak throughout the year. Hence the periods of interest are the night peak of dry and wet seasons.

If extreme weather conditions persist for an extended period resulting in lower production of solar and wind, storage systems would not have sufficient energy to supplement the demand requirement in night peak hours. This phenomenon is referred to as "Dunkelflaute," a German term describing a period when cloudy and windless conditions severely reduce both solar and wind generation. Although such events may not occur regularly, the impact due to an occurrence of such an event can be very severe in the wet season beyond the second decade of the planning horizon. This is due to the high dependance of solar and wind resources, while the development of hydro resources has saturated by that time.

10.16 Impact of Demand Variation

High Demand and Low Demand sensitivities were analysed in order to identify the impact of the demand variation on the Base Case scenario 2025-2044. The demand forecasts used for these two cases are shown in Annex 3.1.

High demand forecast average electricity demand growth rate for twenty-year planning horizon is 5.4%. In order to achieve 70% electricity generation by 2030 with the high demand forecast, solar parks and some wind parks identified under the Base Case scenario 2025-2044 need to be advanced. It was observed that beyond 2030, thermal, renewable, storage and interconnection options were advanced to cater the increased demand.

Due to this increase of power plant capacity additions than that identified in the Base Case scenario, high demand case shows 10% increment in the total present worth cost compared to the Base Case scenario over the planning horizon. Capacity additions for High Demand sensitivity by plant type are summarised in five year periods in Table 10.9.

Table 10.9 - Capacity Additions by Plant Type in High Demand Case

Type of Plant	**2025-2029**	**2030-2034**	**2035-2039**	**2040-2044**	**Total Capacity Addition**	
	(MW)	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(%)**
Renewables	3,035	2,950	2,580	3,670	12,235	65
Gas Turbine	-	430	800	1500	2,730	15
IC Engine	200	-	200	200	600	3
Combined Cycle	465	-	-	-	465	2
Nuclear	-	-	-	600	600	3
Pumped Storage	-	600	-	-	600	3
Battery Storage	305	550	100	50	1,005	5
HVDC	-	-	500	-	500	3
Total	**4,005**	**4,530**	**4,180**	**6,020**	**18,735**	**100**

Note : Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

Twenty-year average electricity demand growth in low demand forecast is 4.7%. Even with a delayed development of some solar and wind parks identified under the Base Case scenario 2025-2044, 70% electricity generation could be achieved by 2030 with the low demand forecast. It was observed that beyond 2030, thermal, renewable and storage projects were delayed due to the reduced demand.

The Low Demand sensitivity reflect a 5% reduction in the total present worth cost compared to the Base Case scenario for 2025-2044. This cost decrease is attributed to the reduction in power plant capacity in the case of lower demand, as fewer investments are required to meet the projected energy needs. Capacity additions for Low Demand sensitivity by plant type are summarised in five year periods in Table 10.10.

Table 10.10 - Capacity Additions by Plant Type in Low Demand Case

Type of Plant	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	2040-2044 (MW)	Total Capacity Addition (MW)	Total Capacity Addition (%)
Renewables	2,485	2,460	2,230	2,340	9,515	63
Gas Turbine	-	330	1,000	700	2,030	13
IC Engine	200	-	200	200	600	4
Combined Cycle	465	-	-	-	465	3
Nuclear	-	-	-	600	600	4
Pumped Storage	-	400	200	-	600	4
Battery Storage	305	350	100	-	755	5
HVDC	-	-	-	500	500	3
Total	**3,455**	**3,540**	**3,730**	**4,340**	**15,065**	**100**

Note : Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

The resulting plans for the two cases are given in Annex 10.8 and Annex 10.9 respectively.

10.17 Impact of Vehicle Electrification

With the growing imperative to decarbonize the transport sector, replacing fuel-based vehicles with electric vehicles (EVs) has become a significant policy focus. This shift will have a direct impact on electricity demand, making it crucial to assess the effect of EV penetration on the Base Case scenario. An aggressive EV penetration scenario, as detailed in Section 3.6 & 3.7 of Chapter 3, has been considered for this evaluation.

To derive the hourly demand for EVs, the analysis considered the inverse pattern of the activity profile of the EV fleet [9]. This approach helps identify periods when vehicles are likely not in use and can be charged without affecting their availability. By mapping the periods of low activity, it is possible to estimate when the demand for charging is likely to be highest. The analysis also incorporated the potential for flexible demand. The flexibility of the demand portion was modeled to account for potential shifts in charging behavior driven by economic incentives. This could be facilitated through mechanisms such as time-of-use tariffs. The implementation of time-of-use tariff should be aimed at reducing the load on the grid during peak periods and promoting more efficient use of renewable energy resources.

The analysis indicates that the additional demand from increased EV penetration can be accommodated by the proposed power plants of the Base Case scenario, while still achieving a 70% renewable energy share until year 2040. Beyond 2040, while it remains technically feasible to meet the additional demand from EVs, it would require a significant increase in thermal generation, particularly during night peak and off-peak hours. However, since majority of thermal additions are based on gas turbine technology, continuous operation of these power plants shall significantly increase operational cost of the plan. It shall be challenging to maintain a 70% renewable energy share beyond 2040 considering the lack of renewable energy production during night peak and off peak hours. However, as mentioned above, strategic planning and policy interventions are required to manage EV charging while optimizing energy resource utilization.

The operational cost under this scenario is expected to increase by approximately USD 1 billion due to the increased demand.

Renewable energy curtailments have been reduced throughout the planning horizon by utilizing more renewable energy during the day for EV charging. Figure 10.28 shows the RE curtailments as a percentage of total ORE generation, with compared to Base Case scenario.

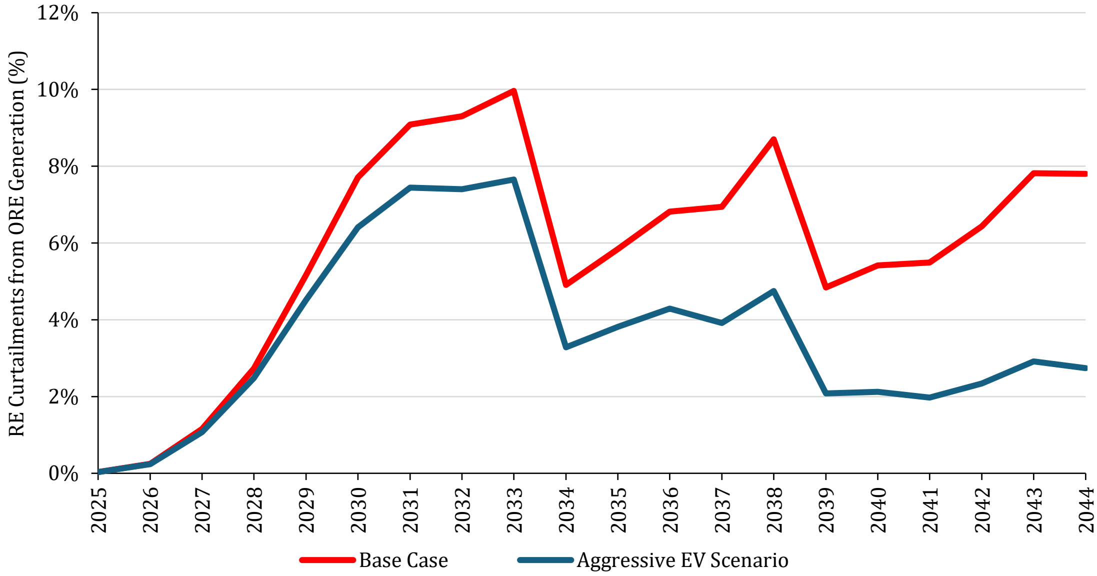


Figure 10.28 - RE Curtailment Comparison of EV Penetration Case and Base Case

The expected weekly system dispatch pattern during the dry season (Jan to Apr) of this scenario in 2044 is illustrated in Figure 10.29.

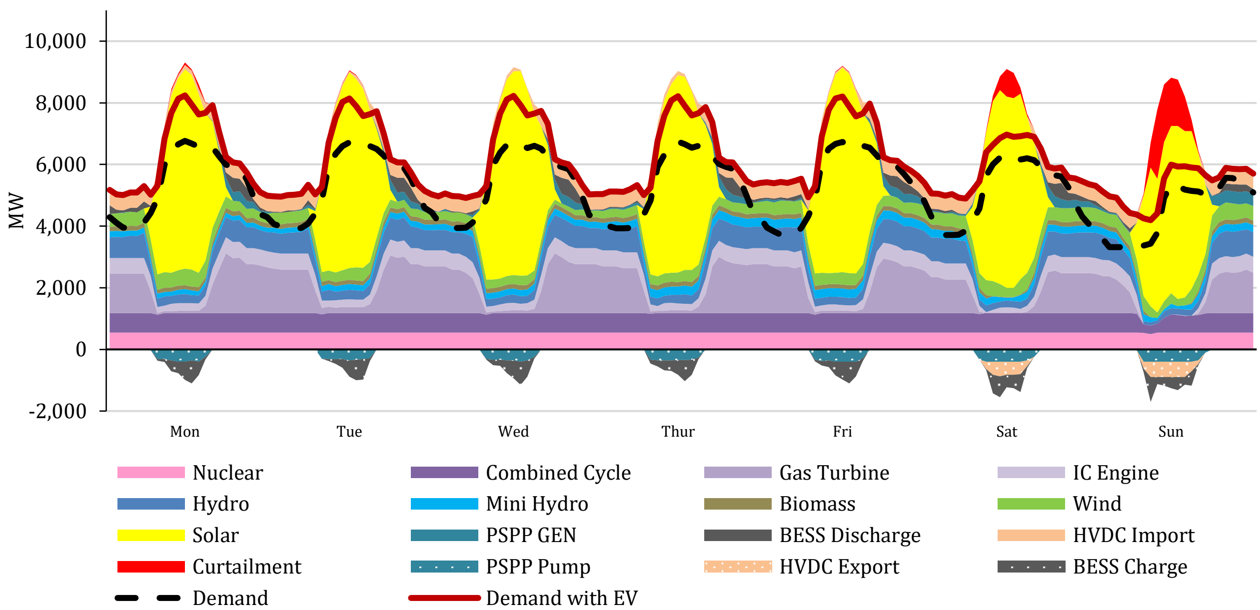


Figure 10.29 - Sample Weekly Dispatch in Dry Period of 2044 with EV Penetration

10.18 Impact of Discount Rate Variation

The discount rate is a crucial component of a discounted cash flow valuation. The discount rate can have a considerable impact on the valuation and hence the selection of power plants in the expansion plan. To study the effect of discount rate on Base Case scenario, analysis was carried out for high and low discount rates compared to 10% used in the Base Case scenario. For low discount rate analysis 3% was used and 15% used for high discount rate.

Low discount rate scenario was carried out to investigate whether high capital cost plants are selected at lower discount rate. In this scenario power plants with comparatively high capital cost were advanced. In the high discount rate analysis, it was observed that the selection of high capital cost power plants was delayed. Therefore, it should be noted that when financing high capital cost power plants, it is required to attract low interest finances in order to be comparatively viable.

10.19 Impact of Delayed Implementation of VRE & Storage Projects

As the Base Case scenario of LTGEP 2025-2044 proposes a plant line up dominated by VRE capacity additions and storage additions, it is important to evaluate the impact on the Base Case scenario if these VRE and storage projects get delayed. This notion was evaluated by the development of this specific sensitivity on the Base Case scenario by delaying all major solar parks, wind parks and battery projects by 2 years and keeping all other plant additions as it is.

As per the results, approximately USD 1.2 billion increase in the present value of operational cost was evaluated due to the delayed implementation of VRE and Storage projects. However, there is notable deferral of present value of investment cost by USD 1.4 billion mainly due to the delayed investment on battery energy storage projects.

10.20 Impact of Delayed Implementation LNG Infrastructure

Natural gas plays a vital role in transition to economical and environmentally friendly operation of the power system. In the Base Case scenario, it was considered natural gas will be available by mid-2027. The impact of delayed implementation of natural gas availability was assessed through sensitivity which further delays the availability of natural gas by an additional 3 years.

As per the results, approximately USD 304 million increase in the present value of total cost was observed in the case of delayed implementation of LNG infrastructure by 3 years compared to Base Case scenario.

10.21 Impact of Utilizing Local Natural Gas

The exploration activities and terms of commercial agreements related local natural gas are required to be further studied to simulate a realistic scenario for utilizing local natural gas. However, the mean of PDASL estimate at a price of 9.25 USD/ MMBtu is considered for analyzing a sensitivity scenario of using local natural gas. The local natural gas availability is considered to be by mid-2028, with the construction of additional offshore pipeline from Mannar basin to western region at a cost of USD 375 million. In this development scenario, LNG import infrastructure development is excluded, hence thermal power plants shall operate for an additional year from oil.

As per the results, approximately USD 343 million saving in the present value of total cost was observed with the introduction of local natural gas by 2028 at a price of 9.25 USD/ MMBtu. The presently discovered reserves at the Dorado well are adequate to meet approximately 60-70% of the electricity sector's total natural gas requirement throughout the entire planning horizon. However, the possibility of flexible extraction of local natural gas according to the requirements of power system is required to be further analyzed.

CHAPTER 11
ENVIRONMENTAL IMPLICATIONS

11.1 Background

Sri Lankan power system until mid-nineties, was a 100% renewable system with only hydro power catering the country's' power demand. Share of fossil fuel thermal generation was increased only during the drought period; hence the power sector had only a minor impact on the environment. However, after exploiting most of the major hydro potential, fossil fuel based power plants were introduced into the power system to cater the growing electricity demand.

Presently, around 50% of the power generation in Sri Lanka, is based on renewable energy sources including major hydro. The balance is generated from fossil fuel power plants. In many instances, electricity generation causes environmental drawbacks. The impact of electricity generation on the environment could be due to one or several factors including particulate emissions, gaseous emissions (CO_2, SO_2, NO_X etc.), warm water discharges into water bodies, liquid and solid waste (sludge, ash), inundation (in the case of large reservoirs), noise pollution and changes of land use. Although many of these are common to any development project, particulate and gaseous emissions are of primary importance in the case of electricity generation using fossil fuels. Further, when developing renewable power plants such as wind and solar, due consideration should be given to localised issues such as conflicts with bird migration routes, bird habitats, water habitats (in case of floating solar), unique land features such as sand dunes, vegetation, changes in land use, inhabitants and noise pollution.

This chapter describes an overview of environmental commitments related to the electricity sector and the impacts due to particulate and gaseous emissions, by the implementation of Base Case Scenario and other selected scenarios of the LTGEP 2025-2044.

11.2 Climate Change

11.2.1 Greenhouse Gases

Greenhouse gases are gases that absorb and emit thermal infrared radiation which causes the gradual heating of Earths' atmosphere which is known as the greenhouse effect. There are natural as well as anthropogenic compounds which contribute to this effect. Water vapour (H_2O), Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and Atmospheric Octane (O_3) (though present only in very minute quantities) are primary greenhouse gases in the Earths' atmosphere. There are also anthropogenic greenhouse gases such as Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs) and Sulphur Hexafluoride (SF_6). For each greenhouse gas, a Global Warming Potential (GWP) has been calculated to reflect how long it remains in the atmosphere and how strongly it absorbs energy.

Table 11.1 - Global Warming Potential of Greenhouse Gases

Greenhouse Gas	GWP values for 100 year time horizon
Carbon Dioxide	1
Methane	25
Nitrous Oxide	298
Hydrofluorocarbons	14,800
Perfluorocarbons	22,800

Source: The Fourth Assessment Report of the United Nations Intergovernmental Panel on Climate Change

11.2.2 GHG Emission Reduction Protocols

The effects of global warming have directly caused concern for the adoption of proper management in climate change. Due to the increasing global concern on climate change, the United Nations Environment Programme and the World Meteorological Organisation jointly established the Intergovernmental Panel on Climate Change (IPCC) in 1988 with a directive to assess the best scientific options on climate change, its potential impacts, and possible response strategies. The United Nations Framework Convention on Climate Change (UNFCCC) was formulated on the basis of initial IPCC findings. In 1992, the UNFCCC was established and signed by almost all countries at the Rio Summit. The decision making body of UNFCCC is known as Conference of Parties (COP) which meets annually. Major events and decisions by Conference of Parties are summarized in Table 11.2.

11.2.2.1 The Kyoto Protocol

During the COP3 meeting in 1997 at Kyoto, Japan, the Kyoto Protocol was accepted. It sets binding targets for 37 industrialised counties and the European Community for reducing GHG emissions. It will amount to an average of 5% against 1990 levels over the five-year period 2008-2012. Recognising that industrialised countries (countries in Annex I of the Kyoto Protocol) are principally responsible for the current high levels of GHG emissions in the atmosphere as a result of more than 150 years of industrial activity, the protocol placed the heavier burden on developed nations under the principle of “common but differentiated responsibilities”. The Kyoto Protocol entered in to force on 16th February 2005. Under the Kyoto Protocol, Annex I countries were aiming to meet their targets primarily through national measures with support from additional market based mechanisms such as emission trading, known as “the carbon market”, Clean Development Mechanism (CDM) and Joint Implementation (JI).

Under the Protocol, country’s actual emissions have to be monitored and precise records have to be kept to the trades carried out. Only the Clean Development Mechanism allows economical emission credit trading among Annex I and non-Annex I Countries.

During COP 18 at Doha Qatar in 2012, developed country parties agreed for a second commitment period up to 31.12.2020, with a revised list of greenhouse gases and commitment by parties to reduce GHG emission by at least 18% below 1990 levels. However, the expected reductions are comparatively low and there is a significant difference in the parties to the second commitment compared to the previous with parties such as Japan, Canada, and Russia not being included for the second commitment.

11.2.2.2 The Paris Agreement

In 2015, the COP21 meeting was held in Paris, where the Paris agreement was introduced in which governments agreed a long-term goal of keeping the increase in global average temperature to well below 2°C above pre-industrial levels and to aim to limit the increase to 1.5°C. Under the Paris Agreement both developed and developing countries must determine, plan, and regularly report on the contribution that it undertakes to mitigate global warming.

No mechanism forces a country to set a specific emissions target by a specific date, but each target should go beyond previously set targets. Many countries submitted comprehensive national climate action plans as Intended Nationally Determined Contributions (INDCs). This agreement was opened for signature for one year from 22 April 2016. This was to enter into force after 55 countries that account for at least 55% of global emissions have deposited their instruments of ratification. Sri Lanka ratified its Nationally Determined Contributions (NDC) in September 2016 [26]. On 5 October 2016, the threshold for entry into force of the Paris Agreement was achieved and was entered into force on November 2016.

Table 11.2 - Summary of Major COP Decisions

COP	Events and Decisions
COP 3 Kyoto, Japan 1997	Kyoto protocol was accepted.
COP13 Bali, Indonesia 2007	Adoption of Bali Road Map which included, – Launching of Adaptation Fund – A review of Kyoto Protocol – Decisions on Technology transfer and Reducing Deforestation related emissions – Ad-Hoc Working Group (AWG) negotiations on a Long Term Corporative Agreement (LCA) and Kyoto Protocol (KP)
COP17/CMP7 Durban, South Africa 2011	The parties agreed to launch a process to develop a protocol or a legal instrument or a legally binding agreement under the convention applicable to all parties. This process is implemented through subsidiary body under the convention, the Ad Hoc Working Group on the Durban Platform for Enhanced Action (ADP). This legally binding agreement was to be agreed upon on or before 2015 and to be implemented by 2020.
COP18/CMP8 Doha, Qatar 2012	Extension of the Kyoto protocol adopted. As a part of negotiations pursuant to the Bali Action Plan, developing country Parties agreed to take Nationally Appropriate Mitigation Actions (NAMAs) in the context of sustainable development.
COP19/CMP9 Warsaw, Poland 2013	Governments advanced the timeline for the development of the 2015 agreement with a view to enabling the negotiations to successfully conclude in December 2015. Countries decided to initiate or intensify domestic preparation for their Intended Nationally Determined

COP	Events and Decisions
	Contributions (INDCs) towards the 2015 agreement, which will come into force from 2020.
COP21/CMP11 Paris, France 2015	Paris Agreement was introduced. Before and during the Paris conference, countries submitted comprehensive national climate action plans as INDCs.
COP 26/CMP16/CMA3 Glasgow, UK 2021	Nations adopted the Glasgow Climate Pact. Decisions include strengthening efforts to build resilience to climate change, to curb greenhouse gas emissions and to provide the necessary finance for both. Nations also completed the Paris Agreement's rulebook.
COP 28/ Dubai, UAE 2023	Having shown that progress was too slow across all areas of climate action, countries responded with a decision on how to accelerate action across all areas by 2030

11.2.3 Climate Finance

Climate finance refers to local, national or transnational financing, which may be drawn from public, private and alternative sources of financing. Climate finance is equally important for both mitigation and adaptation activities. Massive investment is required in order to reduce greenhouse gases significantly as well as for countries to adapt to the adverse effects and reduce the impacts of climate change.

At COP 16, parties decided to establish the Standing Committee on Finance to assist the COP in exercising its functions in relation to the Financial Mechanism of the Convention. This was established with the aim of assisting the COP, with regards to, transparency, efficiency, and effectiveness in the delivery of climate finance. Furthermore, the Standing Committee on Finance is designed to improve the linkages and to promote the coordination with climate finance related actors and initiatives within and outside the Convention. The Convention, under its Article 11, states that the operation of the Financial Mechanism is entrusted to one or more existing international entities. The operation of the Financial Mechanism is partly entrusted to the Global Environment Facility (GEF). In addition to providing guidance to the GEF, Parties have established four special funds: the Special Climate Change Fund (SCCF), the Least Developed Countries Fund (LDCF), both managed by the GEF, and the Green Climate Fund (GCF) under the Convention; and the Adaptation Fund (AF) under the Kyoto Protocol. The Financial Mechanism is accountable to the COP, which decides on its climate change policies, programme priorities and eligibility criteria for funding.

11.3 Country Context

11.3.1 Overview of Emissions in Sri Lanka

When considering the greenhouse gases, CO_2 is one of the primary gases which contribute towards warming of earth's atmosphere. Table 11.3 indicates Sri Lanka's CO_2 emissions from fuel combustion in each sector for the year 2022. It could be observed that approximately 42% of CO_2 emission is from the electricity sector while major contributor for CO_2 emission is the transport sector which accounts for approximately 48%.

Table 11.3 - CO_2 Emissions from fuel combustion

Source	CO_2 Emissions Million Tonne of CO_2	Share
Electricity and heat production	7.7	42%
Manuf. industries and construction	0.9	5%
Transport	8.8	48%
Other sectors	1.1	6%
Total	**18.4**	**100%**

Source: IEA Statistics

The average CO_2 emission factor from electricity generation in the past is shown in Figure 11.1

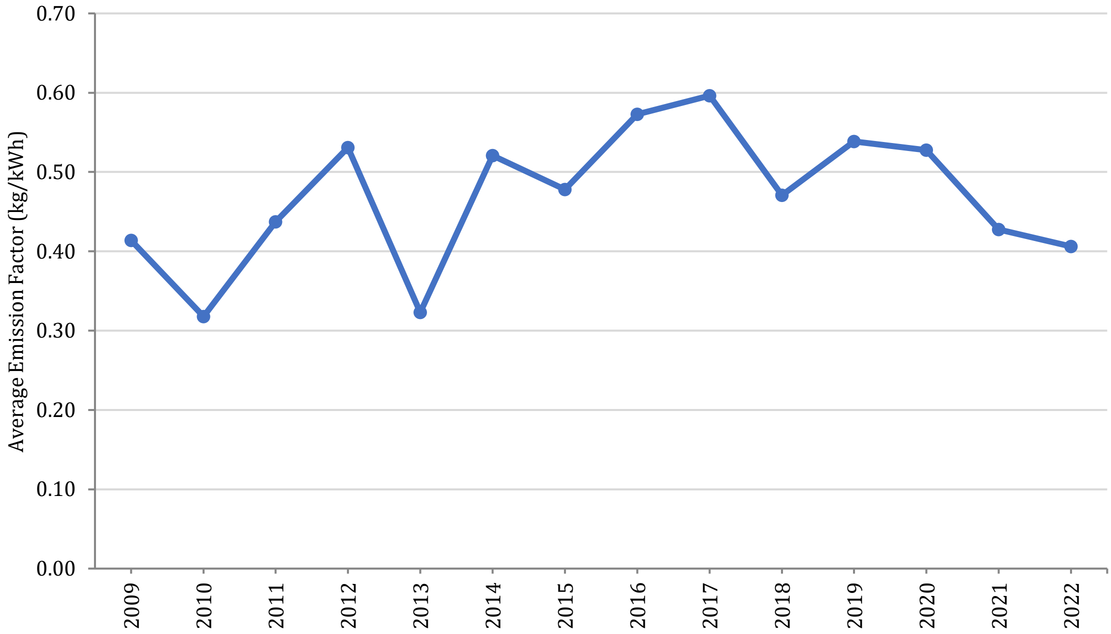


Figure 11.1 - Average CO_2 Emission Factor

Source: Sustainable Energy Authority

Until large thermal plants were introduced to Sri Lankan power system, the power sector only contributed very little to GHG emissions. However, at present the focus is on reducing GHG emissions by integrating more renewable energy in to the power system. In global context, renewable energy resources are playing vital role in reducing GHG emissions and promoted through Government policies. With the focus on increasing renewable energy, more complicated analysis is required to overcome the uncertainties and intermittency which is inherent to renewable energy generation.

11.3.2 Role of Sri Lanka on Climate Change Mitigation

Responding to climate change involves two possible approaches: reducing and stabilizing the levels of heat-trapping greenhouse gases in the atmosphere ("mitigation") and adjustment to consequences of climate change that cannot be avoided ("adaptation").

Sri Lanka has adopted many policy measures that would result in climate change adaptation and mitigation although emission levels are much less than the global values. It is estimated that the total emission contribution of CO_2 emissions from Sri Lanka is as minute as 0.06% of the global total. Even though Kyoto Protocol has not imposed any obligation for non-Annex I countries, Sri Lanka also ratified the Kyoto Protocol as a non-Annex I country in 2002.

In order to address the issues in climate change, a separate dedicated institution named Climate Change Secretariat was formed under the Ministry of Mahaweli Development and Environment, in 2008. National Adaptation Plan for Climate Change Impacts in Sri Lanka 2016-2025 (NCCAS) was developed in 2016. Further, 'The National Climate Change Policy of Sri Lanka' has been developed by the Climate Change Secretariat of Sri Lanka under the Ministry of Mahaweli Development and Environment. Sri Lanka ratified its Nationally Determined Contributions (NDC) in September 2016 in accordance to the Paris agreement through the Climate Change Secretariat of Sri Lanka.

Energy sector is mainly involved in mitigation aspects of climate change and CEB actively participated in developing a 'Low Carbon Development Strategy' (mitigation strategy) which was carried out by Climate Change Secretariat. Further, CEB is an active member of the National Expert Committee on Climate Change Mitigation which provides consultation on various activities related to mitigation.

Following section further describes the different aspects towards reducing GHG emissions and providing sustainable energy to Sri Lankan consumers.

11.3.2.1 Evolution of National Energy Policy

Government of Sri Lanka has given priority in the power sector which is presently dependent on imported fossil fuel, to reduce the present trend by enforcing sustainable energy policies for absorbing more renewable energy into the system.

The National Energy Policy and Strategies of Sri Lanka (2008) stated that, by 2015, Sri Lanka will endeavour to reach a target of at least 10% of the total energy supplied to the grid from Non-Conventional renewable resources. This target was successfully achieved. The subsequent National Energy Policy and Strategies of Sri Lanka (2019) [22] has increased the milestone to realize a minimum 20% share of electricity generated from renewable energy sources excluding major hydro, by 2022. Further Sri Lanka commits for carbon neutrality by 2050 for the first time through this policy.

The General Policy Guidelines in Respect of the Electricity Industry (2019) has given guideline to progress with the vision to achieve 50% of electricity generation from renewable energy sources by 2030 under favourable weather conditions. The latest General Policy Guidelines in Respect of the Electricity Industry (2021) [23] has set the targets of achieving 70% of electricity generation by renewable sources by 2030, carbon neutrality in power generation by 2050 and to cease building new coal power plants. This amendment was primarily based on the commitment given through the updated NDC in July 2021. Further, new addition of firm power plants will be from regasified liquefied natural gas (R-LNG).

11.3.2.2 Hydrogen Road Map

To achieve carbon neutrality by 2050 and meet other Nationally Determined Contribution (NDC) targets, the Petroleum Development Authority of Sri Lanka has developed a comprehensive report on the National Hydrogen Roadmap. This report outlines Sri Lanka's strategy for implementing hydrogen as a key energy source. In alignment with this roadmap, the Long-Term Generation Expansion Plan (LTGEP) 2025-2044 includes hydrogen as a fuel option for future thermal power plants. Hydrogen blend of up to around 30% by volume with natural gas is available at commercial scale power generation at present. Hence, gas turbine power plants (open cycle and combined cycle) and IC engine power plants with blended Hydrogen are planned to be integrated into the system after 2035.

11.3.2.3 Considerations on Development of Nuclear Power

Nuclear power is regarded as one of the technologies having large potential to combat climate change. In view of the policy target of achieving carbon neutrality by 2050, nuclear power has been considered as a possible candidate option.

11.3.2.4 Clean Development Mechanism

In February 2009, the Ministry of Environment and Natural Resources as the Designated National Authority (DNA), to the UNFCC and Kyoto protocol, at the time, developed a draft national CDM policy. The objective of the national CDM policy is *"to achieve sustainable development a) through developing and establishing the institutional, financial, human resources and legal/legislative framework necessary to participate in Clean Development Mechanism (CDM) activities and b) through developing a mechanism for trading of "Certified Emission Reduction" earned through CDM activities for the Government of Sri Lanka."*

The CDM allows emission reduction projects in developing countries to earn Certified Emission Reduction (CER) credits, which can be traded and used by industrialized countries to meet part of their emission reduction targets under the Kyoto Protocol. In Sri Lanka, the key sectors to implement CDM projects can be identified as energy, industry, transport, agriculture, waste management, forestry and plantation. Among these, the energy sector has been identified as having the highest potential.

First CDM project in Sri Lanka was registered in 2005 with UNFCCC. CEB has undertaken one of the large scale projects which is Broadlands Hydro Power Project. The estimated emission reduction from the project is approximately 97 kilo tonnes of CO_2 equivalent per annum.

11.3.2.5 Activities by Ministry of Environment

Ministry of Environment being the national focal point for the UNFCCC conducts many activities continuously to combat climate change. Several projects such as Nationally Appropriate Mitigation Action (NAMA) and Partnership for Market Readiness (PMR) have been concluded in the past.

In order to accelerate industries climate response, a project has been initiated. It is expected to develop a MRV system for the industry sector and validate the industrial sector plan for implementing NDCs through this project. Further it expects to improve policy and regulatory frameworks and capacity of stakeholders to implement these frameworks.

To access international financing to implement projects without hindering the national capacity to achieve NDCs, proper guidelines are essential. In view of this, preparation of "Carbon Trading Policy Framework and Guiding Principles" is ongoing which would enable the country select the projects rationally and transparently. This will provide a base for the country to sign cooperative agreements with interested parties related to the carbon markets and safely and wisely engage with carbon market activities with minimum risk for the country without hindering the achievement of the country's NDCs.

From the Nationally Appropriate Mitigation Actions (NAMA) project, MRV system is initiated for the energy sector as well. Hence, with the support of ADB a technical assistance is implemented which helps to enhance the capacities of NDA's in meeting their climate commitments under the Paris Agreement and currently in a process of developing an MRV system for the Energy sector. As a major stakeholder, CEB will provide necessary data and inputs.

11.3.2.6 Fuel Quality Road Map

An action plan has been developed for fuel quality road map by the Air Resource Management & National Ozone Unit of Ministry of Mahaweli Development & Environment. Introduction of low sulphur Diesel, switching to alternative fuels for transport such as biofuel, railway electrification, promoting electric vehicles, development of fuel quality standards and introducing LNG as a cleaner fuel are some of the activities identified in the fuel quality road map.

11.3.2.7 Loss Reduction

Generation, Transmission and Distribution Loss reduction is also an important measure implemented by CEB towards the path of providing sustainable energy. In 2009, fifteen years ago, the transmission and distribution loss (as a percentage of net generation) was 14.7% and by 2023 it has been reduced to approximately 9.7%.

11.3.2.8 Demand Side Management & Energy Conservation

Energy conservation from Demand Side Management which involves education and awareness of the consumers on purchasing energy efficient appliances, designing households and commercial establishments to be more energy efficient are some measures being carried out in the power sector. All those measures reduce the thermal power generation and results in reduction of GHG emissions.

11.3.2.9 Tree Planting Program

The General Policy Guidelines in Respect of the Electricity Industry (2021), givens directives to introduce counter balancing interventions such as carbon sequestration plantations to reduce carbon footprint of electricity due to power generation.

Ceylon Electricity Board has identified this as a social responsibility and has carried out numerous tree planting campaigns. Since 2015, CEB has planted over 50,000 trees consisting of tree types of

Kaluwara, Kumbuk, Kohomba, Bamboo, Mango, etc. in power plant locations, catchment areas and public places.

11.3.3 Nationally Determined Contributions (NDCs) of Sri Lanka

With signing of the Paris Agreement (COP 21) most countries pledged to reduce green-house gas emissions as well as to adapt to the impacts of climate change. By scaling up renewable energy, countries can sharply reduce the electricity related CO_2 emissions. Nationally Determined Contributions (NDCs) quantify the commitment of each Party (or signatory that has ratified the Paris Agreement) to reduce CO_2 and other greenhouse gas emissions.

Sri Lanka submitted its first Nationally Determined Contributions in September 2016, in accordance with Decision of COP 21 of the UNFCCC. Base year 2013 was considered as the Business-As-Usual scenario and target period of emission reduction is 2021-2030. The scope of NDC comprised of four areas on mitigation, adaptation, loss and damage and means of implementation. Under the scope of mitigation, reducing GHG emissions was focused on five sectors as follows.

a) Energy sector has a 20% GHG emission reduction target in the NDCs, which amounts to 39,383 Gg of the total GHG emissions (196,915 Gg for the period 2020-2030 as per the BAU scenario of the Long Term Generation Expansion Plan 2013-2032 published in October 2013). The reduction of emissions includes 4% unconditional and 16% conditional reduction.

b) The sectors of transport, waste, industry and forestry aims to reduce 10% of its GHG emissions from the BAU scenarios by 2030. This will be 3% unconditional and 7% conditional. However, at the time of submission, BAU emission scenarios were to be estimated in detail and detailed emission reduction plans for these sectors were yet to be developed.

All countries were expected to revise and submit stronger, more ambitious national climate action plans in 2021 to achieve the Paris Agreement goal. Sri Lanka submitted the updated NDC commitments in July 2021 followed by an amendment submission in September 2021 [27].

Mitigation component of the updated NDC submission comprised of six sectors. The revised more ambitious targets for NDC in Electricity sector are as follows.

Target:

A GHG reduction of 25% in the electricity sector is envisaged (5% unconditionally and 20% conditionally) equivalent to an estimated mitigation level of 9,819,000 MT unconditionally and 39,274,000 MT conditionally (total of 49,093,000 MT) of carbon dioxide equivalent during the period of 2021-2030. (Compared to the BAU scenario of the Long-Term Generation Expansion Plan 2013-2032 of Ceylon Electricity Board published in October 2013).

Actions:

a) Enhance renewable energy contribution to the national electricity generation mix by increasing Solar PV, Wind, Hydro and Sustainable Biomass based electricity generations (Target: Develop an additional capacity of 3,867 MW renewable energy over the RE capacity considered in Business-As-Usual scenario, out of which approximately 950 MW are on an unconditional basis and 2,917 MW on a conditional basis)

b) Implement Demand Side Management (DSM) measures by promoting energy-efficient equipment, technologies, and system improvements in a national energy efficiency improvement and conservation(EEI&C) programme

c) Conversion of existing fuel oil-based combined cycle power plants to Natural Gas (NG) and establishment of new NG plants as conditional measures (once the necessary infrastructure is available)

d) Transmission and distribution network efficiency improvements (Loss reduction of 0.5% compared with BAU by 2030) as an unconditional measure (Target: Approximately 1,848 GWh energy savings)

e) Conduct R&D activities to implement pilot scale projects for NCRE sources that have not yet reached commercial maturity and develop other grid supporting infrastructures as conditional measures

Other sectors namely, transport, waste, industry, forestry and agriculture (newly included) have declared separate unconditional and conditional targets sector-wise in detail. Furthermore, Sri Lanka committed for the following.

a) To achieve 70% renewable energy in electricity generation by 2030

b) To achieve Carbon Neutrality by 2050 in electricity generation

c) No capacity addition of Coal power plants

It is expected to revise NDC targets during 2025.

Compatibility with Base Case Scenario

The Base Case scenario of LTGEP 2025-2044 well complies with the NDC commitment, for the period from 2025-2030, compared to the BAU scenario of LTGEP 2013-2032. Since the demand forecast of LTGEP 2013-2032 was higher than the demand forecast in LTGEP 2025-2044, a separate scenario with the plant schedule of BAU scenario of LTGEP 2013-2032 is worked out using the demand forecast of LTGEP 2025-2044 to see even with the reduced demand, still the Base Case scenario of LTGEP 2025-2044 complies with the NDC commitment due to the addition of significant amount of renewable energy. Figure 11.2 illustrates the compatibility of Base Case scenario to Sri Lanka's NDC commitments in electricity sector.

When achieving the NDC activities, the unconditional targets have been declared based on the financial and technical capability already available in the country. Targets that require external financial and technical support to supplement the domestic capacity are declared as conditional targets.

Conditional development includes the technical and financial support for development of 2,917 MW of renewable energy, for conversion of generators to NG, establishment of natural gas power plants and for development of other grid supporting infrastructures such as storage.

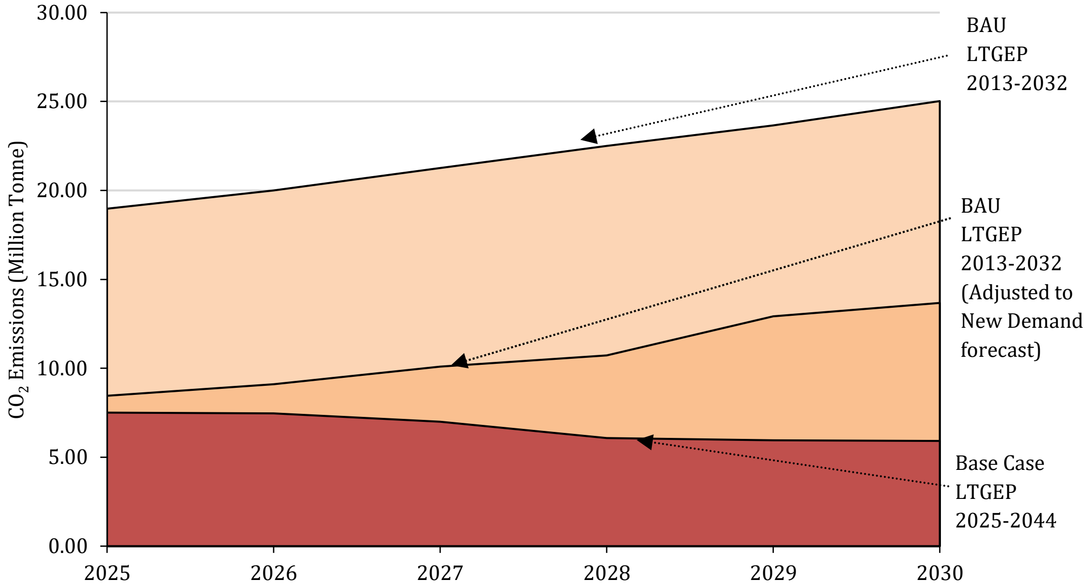


Figure 11.2 - Expected Emission Reduction of Base Case Scenario Compared to NDC - BAU

However, it should be noted that non implementation of these conditional targets on time will significantly impact on the level of emission reductions stipulated in the above. Hence, actual emission reductions achievable should be tracked with the implementation progress of the power projects.

11.3.4 Ambient Air Quality & Stack Emission Standards

In 1994, Government of Sri Lanka has approved The National Environmental (Ambient Air Quality) Regulations which was amended through extraordinary gazette No. 1562/22 in August 2008 [28]. The National Environmental (Stationary Sources Emission Control) Regulations, No. 01 of 2019 was published through extraordinary gazette No. 2126/36 in June 2019 which stipulates the stack emission standards for stationary sources [29]. The regulation enforces minimum stack height as well as stack emission limits for thermal power plants.

All thermal power plants are required to comply with the standards of these regulations, as shown in Table 11.4 and Table 11.5.

Table 11.4 - Ambient Air Quality Standards of Sri Lanka

Pollutant Type	Annual Level (µg/m³)	24 hour level (µg/m³)	8 hour Level (µg/m³)	1 hour Level (µg/m³)
Nitrogen Dioxides (NO_2)	-	100	150	250
Sulphur Dioxides (SO_2)	-	80	120	200
PM10	50	100	-	-
PM2.5	25	50	-	-

Source: Central Environmental Authority

Table 11.5 - Stack Emission Standards of Sri Lanka

Pollutant Type	Oil > 100 MW	Natural Gas >100 MW	Coal > 50 MW
Nitrogen Dioxides (NO_2) (mg/Nm^3)	500 (Steam Turbine) 450 (Gas Turbine / CCY) 650 (IC Reciprocating Engine)	300 (Steam Turbine) 200 (Gas Turbine / CCY) 350 (IC Reciprocating Engine)	650
Sulphur Dioxides (SO_2) (mg/Nm^3)	850	75	850
PM10 (mg/Nm^3)	150	75	150
Smoke (Opacity)	20%	-	15%

Source: Central Environmental Authority

In 2006, World Health Organization (WHO) released a set of guidelines that would address all regions of the world and provide uniform targets for air quality known as the Air Quality Guidelines (AQG), with the purpose of directing national policymakers to create acceptable air quality standards. WHO also created the WHO-Interim Targets to provide flexibility for developing countries to move towards more stringent standards at their own pace. Sri Lankan ambient air quality standards are mostly in line with the WHO interim targets. Most Asian countries based their standards on the WHO AQG and United States Environment Protection Agency (US EPA) National Ambient Air Quality Standards (NAAQS). Table 11.6 shows a comparison of air quality standards adopted by various countries.

Table 11.6 - Comparison of Ambient Air Quality Standards of Different Countries & Organization

(All values in mg/m3)

Pollutant	Averaging time	WHO Guideline (Interim target-1, Interim target-2)	US EPA NAAQS	India	Indonesia	Thailand	Pakistan	**Sri Lanka**
Nitrogen Dioxide (NO_2)	Annual	0.04	0.1	0.04	0.1	0.057	0.04	-
	24 hours	-		0.08	0.15	-	0.08	**0.1**
	8 hour						-	**0.15**
	1 hour	0.2		-	0.4	0.32	-	**0.25**
Sulphur Dioxide (SO_2)	Annual	-		0.05	0.06	0.1	0.08	-
	24 hours	0.02(0.125, 0.05)		0.08	0.365	0.3	0.12	**0.08**
	8 hour						-	**0.12**
	1 hour				0.9	0.78	-	**0.2**
	3 hour		1.3					
	10 minute	0.5		-			-	-
PM 10	Annual	0.02 (0.07, 0.05)		0.06		0.05	0.12	**0.05**
	24 hours	0.05 (0.15,0.1)	0.15	0.1	0.15	0.12	0.15	**0.1**
PM 2.5	Annual	0.01	0.015	0.04		0.025	0.015	**0.025**
	24 hours	0.025	0.035	0.06		0.05	0.035	**0.05**
Suspended Particulate	Annual	-		-	0.09	0.1	0.36	-
	24 hours	-		-	0.23	0.33	0.5	-

Source: World Wide Web, Central Environmental Authority

11.4 Emission Factors

11.4.1 Uncontrolled Emission Factors

One of the problems in analysing the environmental implications of electricity generation is correctly assessing the 'emission coefficients' or more commonly the 'emission factors'. Choice of different sources can always lead to overestimation or underestimation of real emissions. Table 11.7 lists the uncontrolled emission factors *(emissions without considering the effect of control technologies in addition to the standard emission control devices used in planning studies)* which are based on the given calorific values.

Table 11.7 - Uncontrolled Emission Factors (by Plant Technology)

Plant Type	Fuel Type	GCV	GCV	Sulphur	Emission Factor			
		(kcal/kg)	(kJ/kg)	Content (%)	Particulate (mg/MJ)	CO_2 (g/MJ)	SO_2 (g/MJ)	NOx (g/MJ)
Internal Combustion Engine	Fuel Oil	10,300	43,124	2-3.5	13.0	77.4	1.23	1.2
	Auto Diesel	10,500	43,961	<0.3	5.0	74.1	0.04	0.78
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.22
Gas Turbine	Auto Diesel	10,500	43,961	<0.3	5.0	74.1	0.04	0.11
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.04
Comb. Cycle	Auto Diesel	10,500	43,961	<0.3	5.0	74.1	0.04	0.11
	Naphtha	10,880	45,552	0	0.0	73.3	0	0.11
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.04
Coal Steam	Coal	6,300	26,377	<0.6	40.0	94.6	0.455	0.3
Dendro	Dendro	3,224	13,498	0	255.10	0.0	0.0	0.2

Sources: Thermal Generation Options Study [30], 2006 IPCC Guidelines

Basically, CO_2 and SO_2 emission factors are calculated based on the fuel characteristics, while NO_x emissions, which depend on the plant technology, are obtained from data based on OEM manufacturers and previous studies [8]. Generally, particulate emissions depend both on the plant technology and the type of fuel burned. Therefore, the emissions could be controlled by varying the fuel characteristics and by adopting various emission control technologies.

Apart from above hydrogen and natural gas blended (30:70 by volume) IC engines, gas turbines and combined cycles as well as nuclear power plants have been considered for the study. It is expected that CO_2 emissions of the blended fuel would reduce by 10% compared to natural gas however, NOx emission would increase by 15% approximately. Nuclear power plants has no air emissions.

11.4.2 Emission Control Technologies

According to the expansion sequence of Base Case scenario 2025-2044 mentioned in Chapter 10 (Table 10.1), 10,715 MW of renewable energy power plants, 795 MW natural gas fired open cycle and combined cycle gas turbine power plants, 2,000 MW of hydrogen blended natural gas fired open cycle power plants, 600 MW of natural gas fired IC engine power plants and 600 MW of nuclear power plants are to be added to the Sri Lankan power system during the planning horizon. The impact on the environment due to particulate and air-emissions from the thermal power plants out of above additions with that of existing power plants and the effectiveness of using control devices to mitigate those impacts are analysed here. Particulate matter (PM) and gaseous emissions of SO_2, NO_x and CO_2 were considered in the analysis.

When applying control technologies, it is always necessary to have an idea about the availability and capability of different control technologies. Studies have shown that, in many cases, the use of state-of-the-art engineering practices could meet the stipulated air quality standards without specific control devices. However, there are instances where emission control is mandatory.

For example, in the case of coal plants, the use of high-quality, low-sulphur coal (0.65% S) reduces SO_2 emissions to levels below the standard, but there has to be some form of control over particulate emissions. Lakvijaya coal power plant has a Sea Water Flue Gas Desulfurization unit (FGD) installed for further reduction of SO_2 emissions and an Electrostatic Precipitator (ESP) for control of PM.

Hence, in the present study, control technologies considered in the proposed coal plants (coal plants not considered for the Base Case scenario, but in other scenarios) are as follows; ESPs for the control of particulate emissions, sea water FGD for control of SO_2 and low NO_x burners and two stage combustion for the control of NO_x. Coal power plants operating in Sri Lanka are mostly designed for low sulphur coal (0.65% sulphur) as fuel. Selective Catalytic Reduction (SCR) is also considered as an option for reduction of NO_x. Indoor coal storages or silos are proposed in new coal power plants in order to curb pollution due to coal dust.

When considering the gas turbine technology, the low-NOx burners are an integrated part of most of the commercially available simple cycle and combined cycle power plants, which are capable of reducing NOx emissions to a very low level. However, the NOx emissions of IC engine power plants tend to be higher and hence mitigatory measures such as SCR should be considered as an emission control technique in the proposed IC engine power plants.

Carbon Capture and Storage (CCS) is a technology that collects and concentrates the CO2 emitted from large point sources such as power plants, transports it to a selected site and deposits it, preventing the release into the atmosphere. With the rising global energy consumption, technologies such as CCS becomes inevitable to avoid atmospheric greenhouse gas emissions and related climate consequences. Nevertheless, the technology is still being developed and improved. The present study has considered the combined cycle power plants integrated with CCS technology as one of the potential candidate options. However, this option was proved to be unviable due to high cost.

Nuclear power plants are notable for having no air pollutants, making them a cleaner energy source in terms of air quality. However, they present unique environmental challenges, primarily concerning the management of radioactive waste. Proper handling, storage, and disposal of this waste are critical to ensure safety and minimize environmental impact. These considerations must be addressed with stringent protocols and advanced technology to mitigate any potential risks associated with nuclear power plants.

Table 11.8 shows the abatement factors of typical control technologies available for controlling emissions, during and/or after combustion. The values used in the study are shown shaded. The stricter the emission standards and environmental regulations are, higher the cost it has to be incurred to incorporate mitigation measures. Such costs of the control technologies considered are included in the project costs of candidate plants of the Long Term Generation Expansion Plan which is also a part of the environmental damage mitigation cost.

Table 11.8 - Abatement Factors (%) of Typical Control Devices

Device	SO_2	NO_X	TSP[1]	PM	CO	CH_4	NMVOC[2]
Fabric Filter			99.5	99.5			
Electro Static Precipitator				99.8			
Selective Catalytic Reduction		75.7					
Dry FGD	50						
Wet FGD	92.5		90	90			
Sea Water FGD	93.9						
Low NOx Burner – Coal		25			-10	-10	-10
Low NOx Burner – GT/ CCY[3]		80					

Sources: Decades Manual & Coal feasibility Study Reports

[1] TSP - Total Suspended Particles

[2] NMVOC - Non Methane Volatile Organic Compounds

[3] - (NOx abatement % for GT / CCY plants is based on a reduction from 350 ppm to 70 ppm)

11.4.3 Emission Factors Used

In the present study, emission factors were either calculated based on stoichiometry or taken from the actual measured values or calculated based on design and operational data for candidate plants. Emission factors were chosen from a single source [8] where sufficient data were not available. Table 11.9 shows the actual coal power plant data used in the study.

Table 11.9 - Emission Factors of Existing Coal Power Plant

GCV of coal (kcal/kg)	Sulphur Content (%)	Emission Factor			
		Particulate (mg/MJ)	CO_2 (g/MJ)	SO2 (g/MJ)	NO_x (g/MJ)
6,300	0.7	15.00	94.6	0.056	0.260

Taking into consideration the emission factors mentioned in Table 11.7, Table 11.9 and the characteristics of the power plants, emissions per unit of electricity generated from candidate power plants are calculated as shown in Table 11.10

Table 11.10 - Emission Factors of Candidate Power Plants

Plant Type	Fuel Type	Full Load Heat Rate kcal/kWh	Emission Factor (tonne/GWh)			
			PM	CO_2	SO_2	NOx
50 MW NG IC Engine	NG	1,987	0.0	466.7	0.0	1.8
50 MW FO IC Engine	FO	2,086	0.1	676.5	10.7	10.7
100 MW NG IC Engine	NG	1,987	0.0	466.7	0.0	1.8
100 MW FO IC Engine	FO	2,086	0.1	676.5	10.7	10.7
200 MW NG IC Engine	NG	1,987	0.0	466.7	0.0	1.8
200 MW FO IC Engine	FO	2,086	0.1	676.5	10.7	10.7
50 MW NG Gas Turbine	NG	2,921	0.0	686.1	0.0	0.5
50 MW NG Gas Turbine (Aero)	NG	2,377	0.0	558.3	0.0	0.4
100 MW NG Gas Turbine	NG	2,469	0.0	579.9	0.0	0.4

Plant Type	Fuel Type	Full Load Heat Rate kcal/kWh	Emission Factor (tonne/GWh)			
			PM	CO_2	SO_2	NOx
100 MW NG Gas Turbine (Aero)	NG	2,337	0.0	548.9	0.0	0.4
200 MW NG Gas Turbine	NG	2,489	0.0	584.6	0.0	0.4
300 MW NG Gas Turbine	NG	2,307	0.0	541.9	0.0	0.4
200 MW NG Combined Cycle	NG	1,755	0.0	412.2	0.0	0.2
300 MW NG Combined Cycle	NG	1,751	0.0	411.3	0.0	0.2
400 MW NG Combined Cycle	NG	1,581	0.0	371.3	0.0	0.2
500 MW NG Combined Cycle	NG	1,557	0.0	365.7	0.0	0.2
300 MW High Efficient Coal	Coal	2,241	0.1	889.3	0.3	0.3
600 MW Super Critical Coal Plant	Coal	2,082	0.1	826.2	0.3	0.3
600 MW Nuclear Power Plant	Nuclear	2,685	0.0	0.0	0.0	0.0
5 MW Dendro	Dendro	5,694	6.1	0.0	0.0	4.8

11.5 Environmental Implications – Base Case

Presented below is a quantitative analysis of the emissions associated with the Base Case scenario described in Chapter 10. The total particulate and gaseous emissions (controlled) under the Base Case scenario are shown in Table 11.11 and Figure 11.3.

Table 11.11 - Air Emissions of Base Case

1000 tonne/year

Year	PM	SO_2	NO_x	CO_2
2025	3.2	26.5	28.1	7,508
2026	3.8	25.5	26.9	7,457
2027	3.7	11.2	20.5	6,990
2028	3.9	2.5	15.5	6,073
2029	4.1	2.3	15.0	5,947
2030	4.4	2.3	15.0	5,909
2031	4.7	2.1	15.2	6,017
2032	5.1	2.1	15.8	6,388
2033	5.4	2.2	16.2	6,533
2034	6.6	2.2	16.4	6,618
2035	6.7	2.2	16.4	6,694
2036	6.8	2.3	17.2	7,165
2037	7.0	2.4	18.3	7,690
2038	6.7	2.4	19.1	8,019
2039	7.4	2.3	17.8	7,282
2040	7.4	2.3	18.4	7,647
2041	7.0	1.5	14.8	7,060
2042	6.9	1.6	16.3	7,804
2043	6.7	1.6	17.0	7,900
2044	6.0	0.0	6.6	4,235

With the aggressive development of renewable energy power plants to meet the increasing demand, emission levels of CO_2 shows a continuous decreasing trend until around 2030. However, afterwards increasing of the thermal generation by natural gas based power plants increases the CO_2 emissions. A significant reduction of CO_2 could be seen in 2044 after introduction of nuclear power plant. Although the energy contribution is low from biomass plants, it is the major contributor to the increasing trend of the PM emissions during the planning horizon.

The higher level of particulate, SO_2 and NO_x emissions in the initial years is due to dispatch of oil fired power plants. The SO_2 and NO_x levels are maintained at a steady level after the oil fired plants are retired and renewable power plants are commissioned. SO_2 emissions become negligible in 2044 after retirement of coal power plants and introduction of nuclear power plants. NO_x levels slightly increases after 2030 due to the increased dispatch of natural gas/hydrogen based power plants and significantly reduces in 2044.

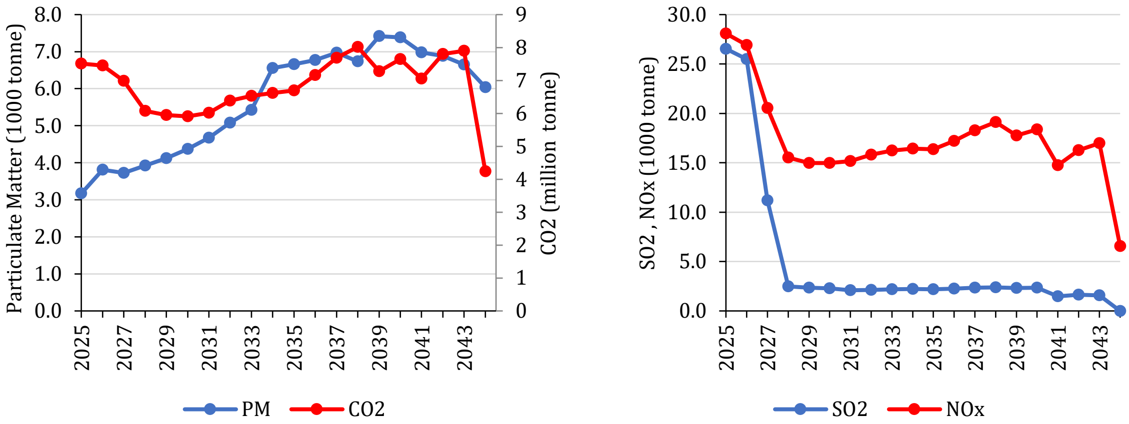


Figure 11.3 - CO_2, PM, SO_2 and NOx Emissions of Base Case Scenario

According to Figure 11.4, SO_2 and NO_x emissions per kWh shows a levelised trend. The higher energy dispatch of furnace oil fired power plants with heavy SO_2 and NO_x pollutants has led to much higher per unit emission levels in the initial years. Per unit CO_2 emissions shows a continuous decreasing trend.

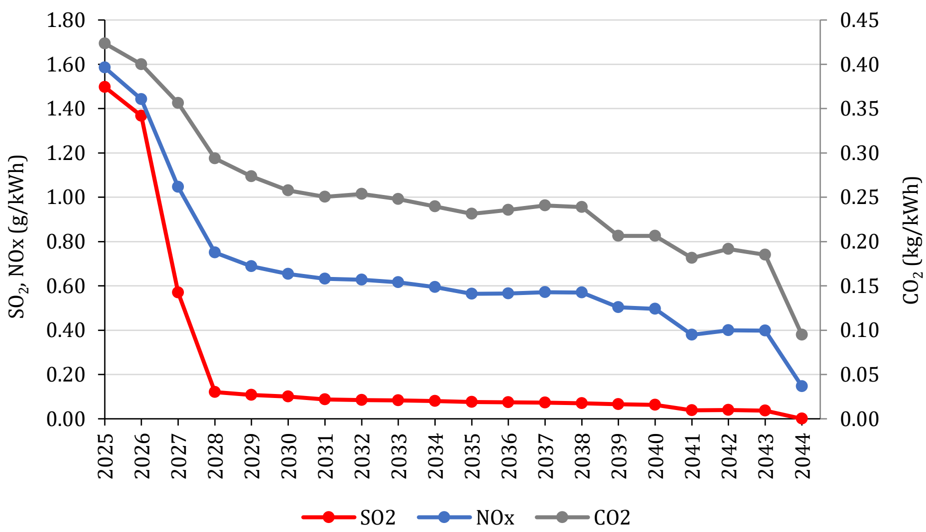


Figure 11.4 - CO_2, SO_2 and NOx Emissions per kWh Generated

Figure 11.5 shows the past actual and forecast values of Average CO_2 emission factors for the Base Case scenario. Average CO_2 emission factor of the Base Case scenario shows a decreasing trend in the long term.

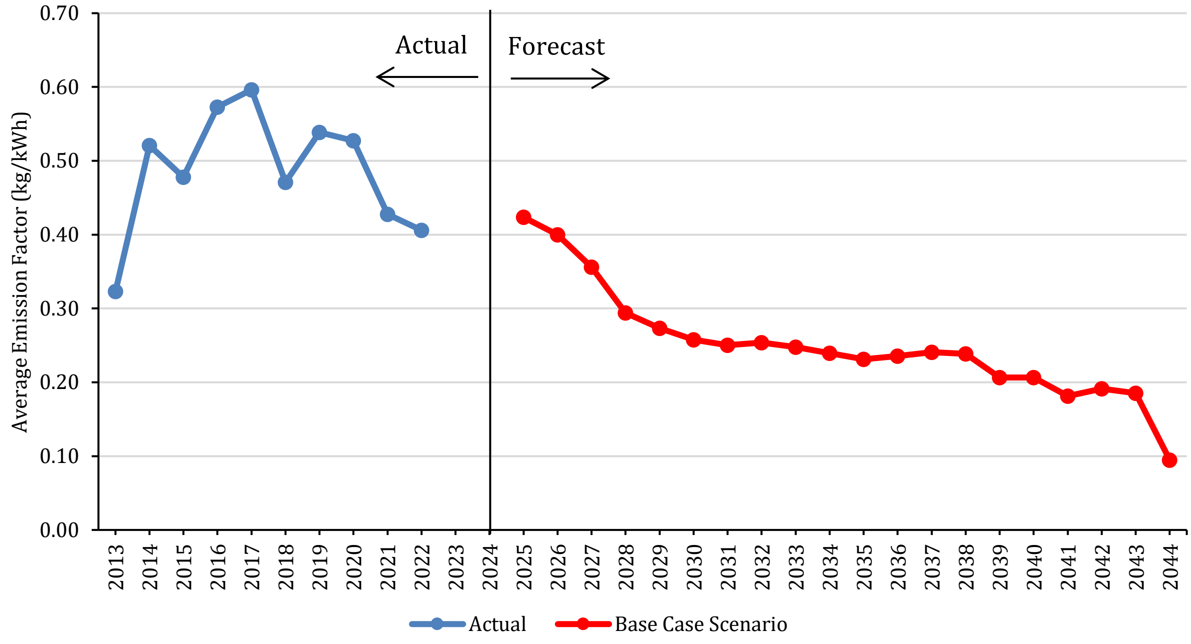


Figure 11.5 - Average CO_2 Emission Factor Comparison

11.6 Environmental Implications – Other Scenarios

11.6.1 Comparison of Emissions

The effects on emissions under following key scenarios were analysed and evaluated against the Base Case (Scenario 3) emission quantities.

a) Scenario 5 - Achieve 70% RE by 2030, increase to 80% from 2040 onwards, With aggressive Solar and BESS development, With 500 MW HVDC interconnection, No coal capacity additions

b) Scenario 6 - Maintain 65% RE from 2028 onwards, With coal capacity additions

c) Scenario 7 - Maintain 60% RE from 2027 onwards, With coal capacity additions (Reference Case)

d) Scenario 8 - Maintain 60% RE from 2027 onwards, No coal capacity additions

In Base Case (Scenario 3) and Scenario 5, emissions from imports through HVDC interconnection are not accounted as they are not emitted within the boundaries of the country.

Figure 11.6 depicts the SO_2 emissions for the planning horizon for above scenarios. It can be seen that the SO_2 are higher during the initial years due to the dispatch of oil power plants. After 2028 the SO_2 emissions have drastically reduced in all scenarios due to introduction of natural gas.

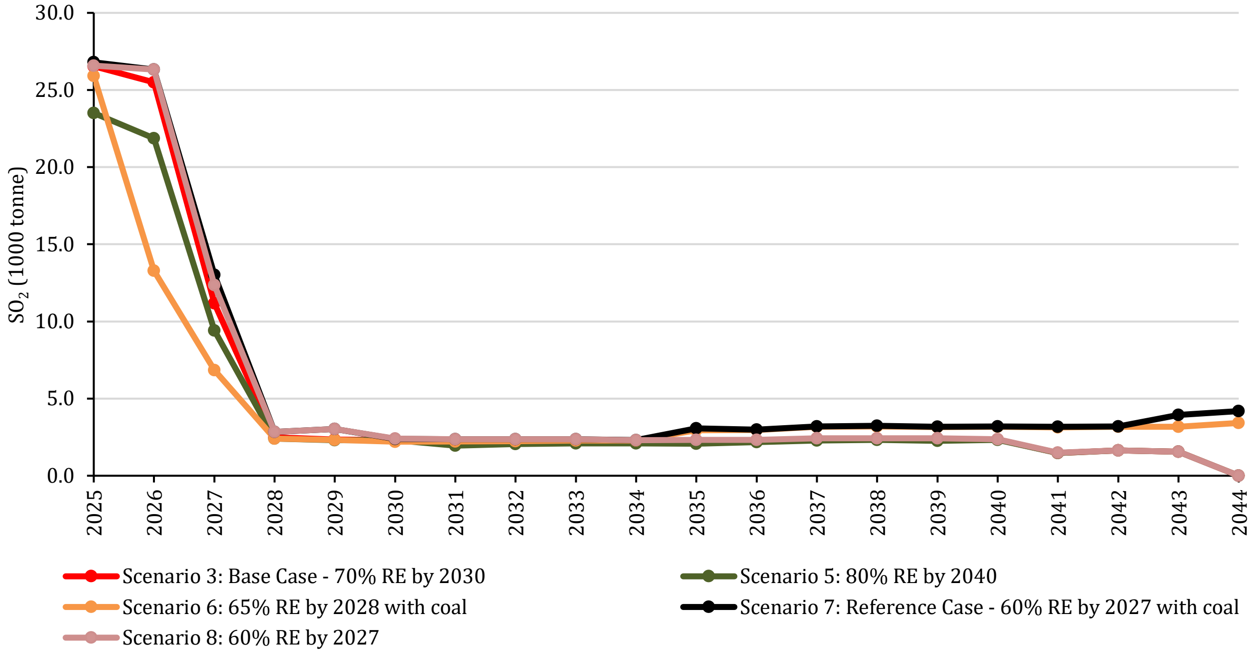


Figure 11.6 - SO_2 Emissions

Figure 11.7 illustrates the NO_x emissions during planning horizon for all scenarios. The higher amount of NO_x emissions would be reduced with the retirement of oil power plants but would gradually increase during the horizon in all scenarios due to the introduction of natural gas based power plants. It is important to note that while hydrogen offers a promising solution for reducing CO_2 emissions, its impact on NOx emissions could be detrimental. Due to introduction of hydrogen blended natural gas power plants the NOx emissions further increase after 2035. However, NOx emssions significantly reduces in 2044 after retirement of coal power plants.

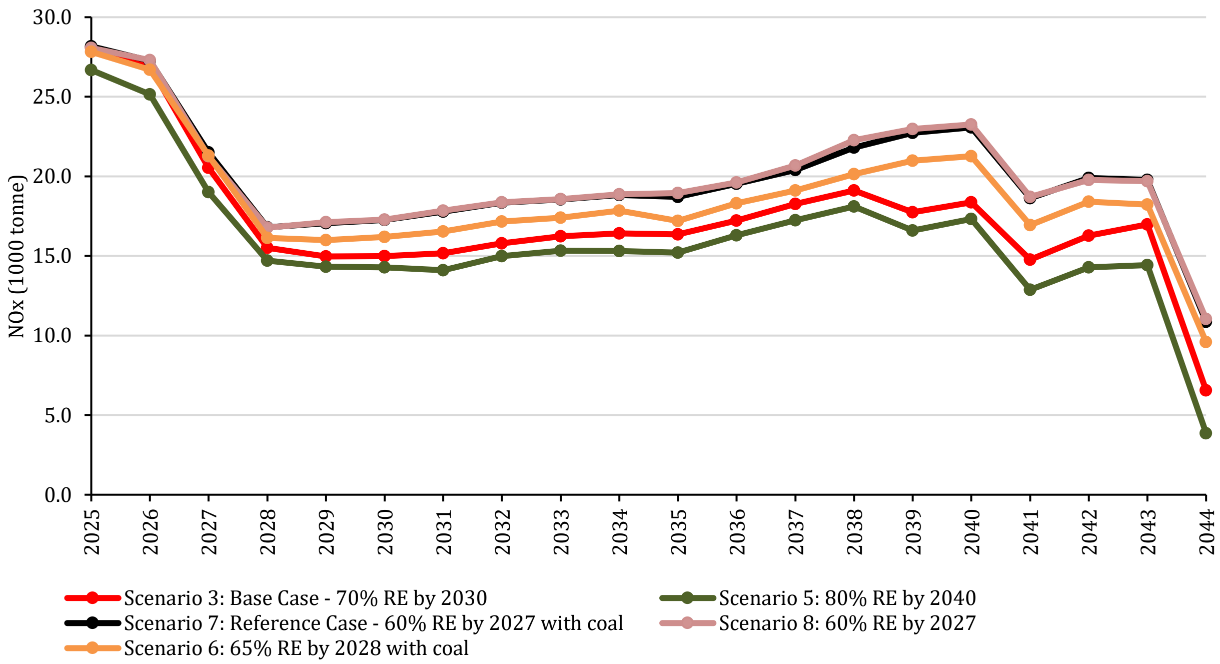


Figure 11.7 - NOx Emissions

Figure 11.8 shows the CO_2 emissions of the scenarios. Reference Scenario has higher CO_2 emissions compared to Base Case scenario due to lower share of new renewable energy power plants and having coal power plants. 80% scenario has the lowest CO_2 emissions over the planning horizon. As mentioned above, CO_2 emissions from HVDC are not accounted in scenario 3 & scenario 5. Nuclear power development in 2044 has reduced CO_2 emissions drastically in scenario 3 and 5.

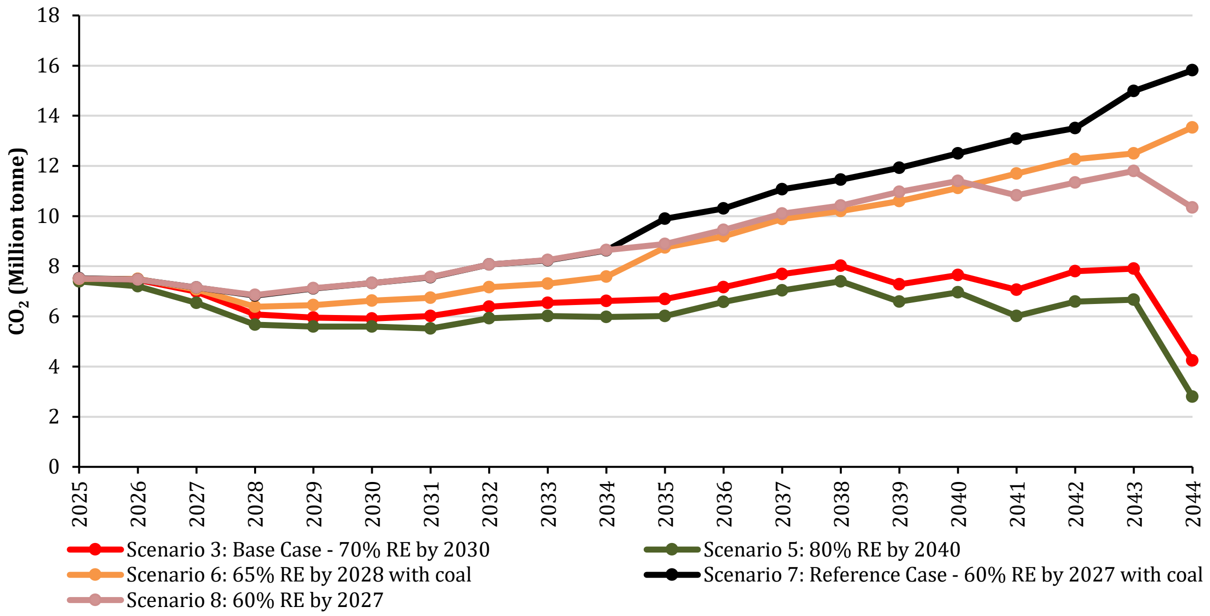


Figure 11.8 - CO_2 Emissions

Figure 11.9 shows the comparison of PM emission related to various scenarios. Future biomass power plants have contributed mainly towards the increase in PM emissions.

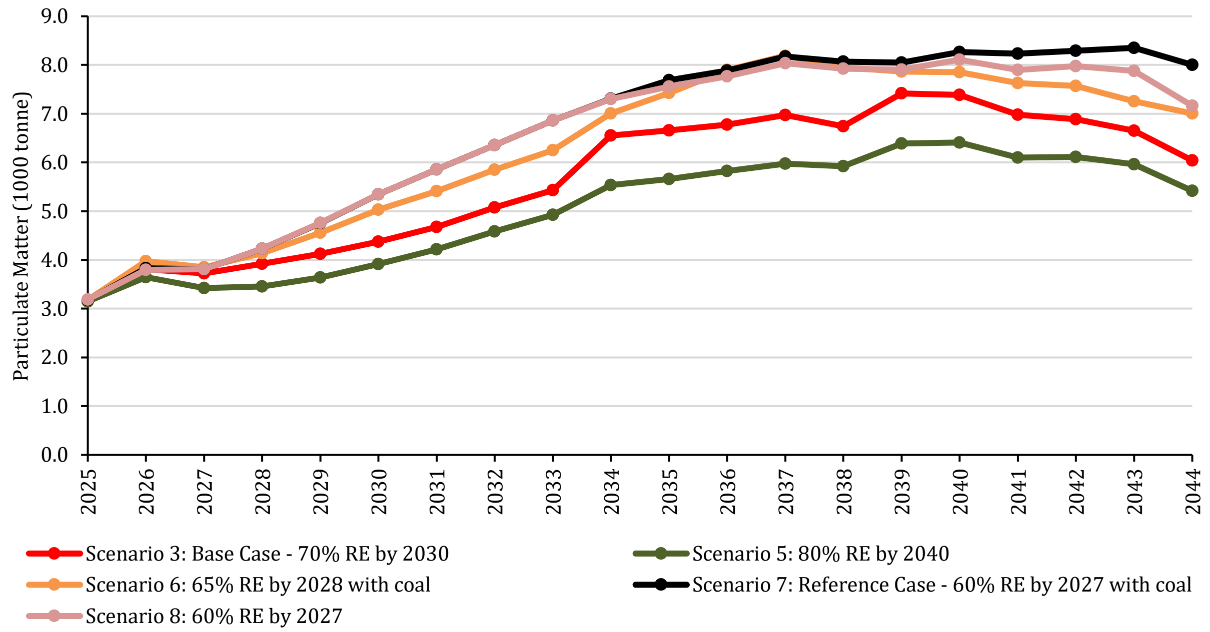


Figure 11.9 - Particulate Matter Emissions

11.6.2 Cost Impacts of CO_2 Emission Reduction

There are tools and techniques developed in order to identify the cost effectiveness of different mitigation options. Marginal Abatement Cost Curve (MACC) is a technique developed to identify the cheapest abatement options among several techniques and in which order they should be prioritised. It is a visual representation showing GHG abatement potentials of various abatement options as a function of GHG abatement costs, and placing these mitigation measures in ascending order of cost-effectiveness. This could be useful in identifying the price of carbon for different GHG emission reduction options and also the overall cost to the economy of meeting specific emission targets. Therefore, it can be a useful analytical tool in defining a cost-effective investment program for Sri Lanka in the pathway for carbon neutrality.

Comparison of total CO_2 emission with total system cost is shown in Figure 11.10. Scenario 3 & 5 does not reflect CO_2 the emissions from imports.

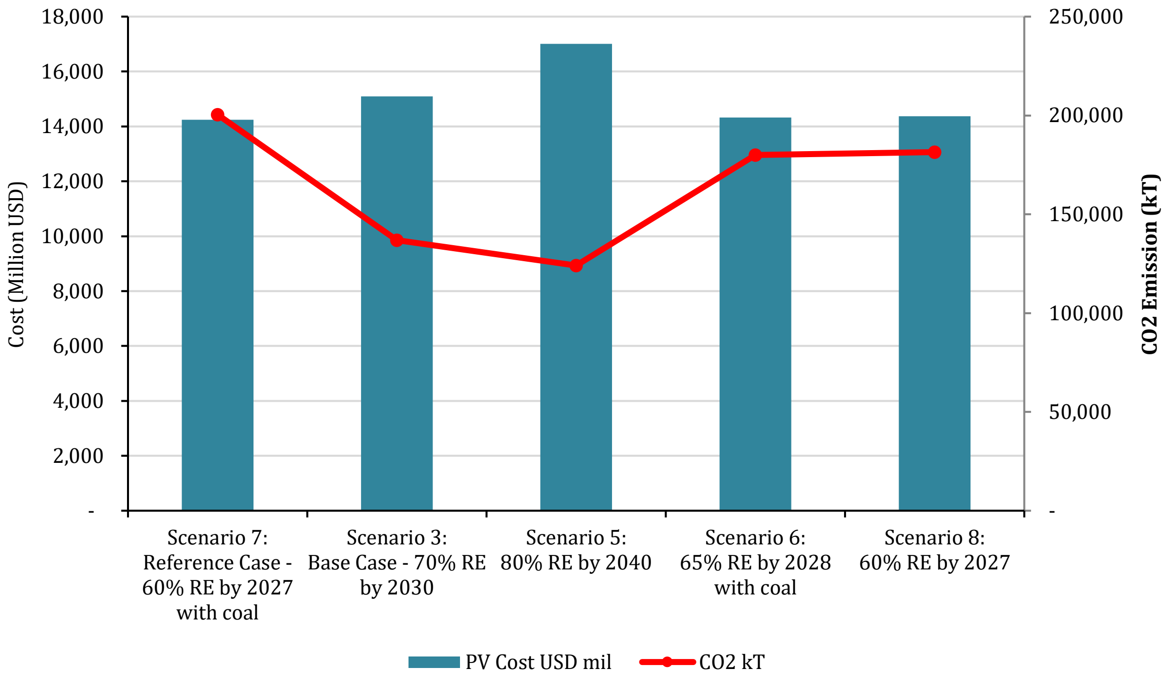


Figure 11.10 - Comparison of System Cost with CO_2 Emissions

Further, the incremental cost of each case is shown in Figure 11.11 by comparing the cost differences and the reduction of CO_2 emissions in each case compared to Reference Case.

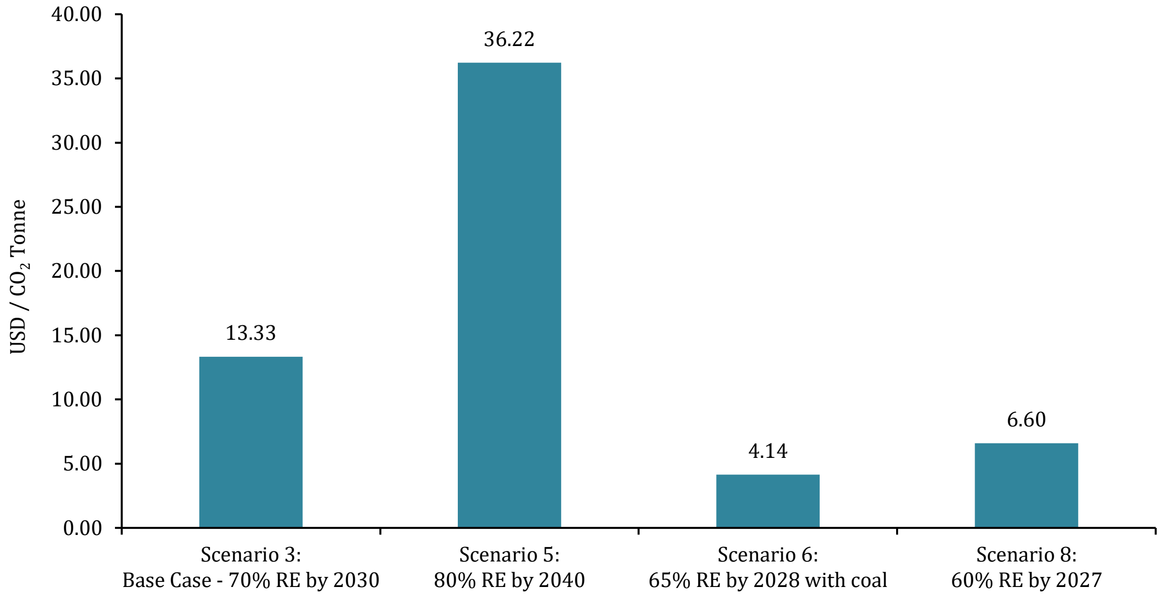


Figure 11.11 - Comparison of Incremental Cost for CO_2 reduction

11.7 Externalities

Externalities as discussed in generation planning are the consequences of a generation activity which indirectly affects other parties without being reflected in market prices. Externalities can be either a positive benefit or negative cost with relation to power generation.

Like any other heavy industry, power industry too causes negative impacts on the social and natural environment in varying degrees. The negative impacts at local level include, releasing of pollutants to local environment, release of waste heat, noise pollution, inundation of lands due to construction of hydro reservoirs, disruption of bird routes by wind plants, etc. The global level impacts are mainly caused with releasing of Green House Gases (GHG). These negative externalities could have non quantifiable impacts to climate change, health, society, agriculture and even bio diversity.

As for the positive impacts, technologies that are capable of generating low cost electricity shall increase the domestic production capabilities contributing to increase the country's GDP. Furthermore, power generation can produce by-products that could be used in manufacturing industries. For example, power generation through coal produces by-products that are used in cement industry and brick manufacturing industry.

Such impacts, when expressed in monetary terms, are called externalities. Estimates of such externalities of different power generating technologies give policy makers a valuable input to decide countries energy policy, generating/fuel mix, future power sector strategies, etc.

As the environmental impacts are a combined effect of all industries, estimating externality costs of specific power generating technology/fuel is a challenge and can be highly subjective due to the difficulty in isolating the contribution of power industry from the impacts from all other industries. Further, as electricity accounts for a less than 15% share of the total energy usage in the country, isolating the impacts of power industry from the balance 85% is very difficult. Thus, expressing the externality costs in monetary terms is a highly subjective exercise as seen from results of studies done in other countries.

Environmental and social impacts of development projects cannot be completely eliminated but can only be contained within ''acceptable limits". Such limits are stipulated in the environmental laws, regulations and standards of a country. This Long-Term Generation Expansion Plan is prepared meeting all such laws and standards. When it comes to reducing GHG emissions, Sri Lanka has obligations under Nationally Determined Contributions (NDC) to reduce emissions unconditionally as well as conditionally, depending on availability of carbon finance as discussed in section 11.2.3. This LTGEP is prepared complying with all such the international commitments related to climate change mitigation.

11.7.1 Local Environmental Damage Issues

Local impacts to social and natural environment can arise due to many causes such as,

a) Local Air pollution as a result of fuel combustion.

b) Pollutants released including waste heat and effluents.

c) Disposal of residual waste products such as ash.

d) Noise emanating from thermal power plants and wind turbines.

e) Effects due to hydro reservoirs.

f) Impact on aquatic ecosystems due to floating solar power

g) Effects on bird migratory routes and other eco systems

Such localized impacts can have adverse social, environmental and health related issues. However, externality costs of such local impacts cannot be generalised by power generating technology and be adopted to Sri Lanka using studies done in other countries.

It is well known that damage costs are a function of income level of a country, population density around power plants and the specifications of each power plant. Sri Lanka being an island, the localized effects would be entirely different to that of other countries where plants are located inland and therefore health damage issues associated with air pollutants and thermal discharges need to be evaluated in Sri Lanka specific studies. Studies done in other countries for certain generating technologies such as coal power plants cannot be straightaway adopted to Sri Lanka as coal plants operated in such countries are of much older technologies compared with the existing coal power plants of Sri Lanka. Therefore, country and location specific studies are required to be done to reasonably estimate the damage costs even though that too can be highly subjective.

11.7.2 Global Damage Issues of GHG Emissions

Global impacts of power generation are primarily due to release of CO_2 during combustion process. However, such global impacts of power generation are not only limited to the impacts due to conversion of fuels to electricity at the point of power generation, but also includes the impacts during the total supply chain of the fuel from the mine to the plant. When the total life-cycle emissions of LNG, which include emissions at the point of mining/extraction, liquefaction, transportation, regasification and combustion are considered, the results are totally contrast to the emission of GHGs during combustion only. Global studies have been conducted to prove that when life cycle emissions of natural gas, liquid fuel oils and coal are considered, the equivalent GHG emission of natural gas (which consists of methane having a GHG effect 28 times than CO_2) is more than that of other liquid fuel oils and are somewhat in the same range of coal. Such indirect emissions are present not only in thermal power generating sources but are common to any other type of generating source including hydro, wind and solar PV. Disposal of solar PV panels after de-commissioning has raised a huge global environment concern and re-cycling technologies are yet emerging. Thus, estimating the global impact of GHGs as a part of externalities is highly subjective and is beyond the scope of economic planning.

However, CEB had enhanced the operational specifications of future candidate power generating technologies to further reduce the environmental impacts of such technologies over and above what is stipulated under law. Additional costs to do so have already been considered and factored in to the capital costs of candidate thermal power plants in this planning study. Thus, CEB has already considered additional costs to bring down externality costs of power generating technologies, to be well below the threshold values of environmental regulations and hence the costs of externalities have been internalized in to the planning studies in the form of additional capital investment.

11.8 Pathway to Carbon Neutrality

Carbon neutrality is a state of net-zero carbon emissions achieved by a balance between emitting carbon and absorbing carbon (from the carbon sinks) in the atmosphere. Reaching global carbon neutrality by mid-century and keeping global warming below 1.5˚C of the pre-industrial level was one of the main objectives of Paris agreement. Many countries pledged for carbon neutrality and put a target year on their policies or laws to achieve this.

Few countries including Bhutan, Suriname and Panama have already achieved carbon neutrality and are recognized as carbon negative. Maldives and Uruguay have ambitious targets of achieving net-zero by 2030 and Finland is leading the path to net zero by committing to achieve carbon neutrality by 2035. The majority of countries are aiming for a zero-carbon economy by 2050 including Sri Lanka. Few countries including major emitters such as China and India have carbon neutrality pledges beyond 2050.

With regard to the pathways in achieving carbon neutrality, reduction of greenhouse gas emissions plays a vital role but is not the only key option. Offsetting carbon emissions (in addition to avoidance and reduction) through artificial or natural carbon sinks is also an important factor in reaching this goal. Carbon sinks are systems that absorb more carbon than they emit, such as forests, soils and oceans.

Carbon Sequestration refers to the process of removing carbon from the atmosphere and depositing it in a reservoir (carbon sinks) for a longer period of time. This process is a promising approach to remove CO_2 emissions from the atmosphere. Major types of carbon sequestration are biological, geological and technological. Biologic carbon sequestration refers to storage of atmospheric carbon in vegetation, soils and aquatic environments. Therefore, reforestation (planting trees in a forest where the number of trees has been decreasing) and afforestation (creating new forest) becomes important as they are natural sinks. This will require active participation from forestry sector of the country. Geologic carbon sequestration is the process of storing CO_2 in underground geologic formations. The CO_2 is usually pressurized until it becomes a liquid, and then injected into porous rock formations in geologic basins. New ways to remove and store carbon from the atmosphere using innovative technologies are being explored at global level and these methods are known as technological sequestration. Artificial trees are a means by which carbon is directly captured from the air. However, this process is energy intensive and expensive. Furthermore, ways to use CO_2 as a resource (for example in Graphene production) are also being explored globally.

In the pathway to carbon neutrality, possibility of green hydrogen production, storage and usage is also becoming important. Hydrogen can be made from several abundant sources such as natural gas or water. The process and energy used determine whether the hydrogen produced is 'low-carbon' or not. Hydrogen made from fossil fuel such as natural gas must incorporate carbon capture, utilization and storage (CCUS) into the process to be low-carbon. When hydrogen is made from water via electrolysis, the process must be powered by a low-carbon source such as renewable energy to be a low-carbon process. This process is commonly referred to as 'green hydrogen'. This could be used as a seasonal storage to increase the renewable absorption (by reducing curtailments in RE generation) and further be utilized to operate natural gas driven thermal plants on blended hydrogen (hydrogen mixed with natural gas). A key barrier for low-carbon hydrogen is the cost gap with hydrogen from unabated fossil fuels. But with the declining cost of renewable energy this could be a promising technology in the future.

Nuclear power plants play a pivotal role in the journey toward carbon neutrality. As a reliable and consistent source of low-carbon energy, nuclear power offers a significant advantage in complementing renewable energy sources, such as wind and solar, which are variable by nature. By providing a steady base load of electricity, nuclear power helps to stabilize the grid and ensures energy security. With the global trends of phasing out of fossil fuels for power generation, the expansion of nuclear power becomes increasingly important, not only in maintaining energy supply but also in significantly reducing the carbon intensity of electricity generation. This makes nuclear power an essential component of the diversified energy portfolio needed to achieve carbon neutrality in a country.

The pathway to achieving carbon neutrality in the power sector in Sri Lanka by 2050, as illustrated in Figure 11.12, is a comprehensive strategy that aligns with the Base Case scenario of the LTGEP. This plan is centered on the integration of renewable energy sources including storage solutions, which will play a crucial role in reducing the sector's carbon footprint. A critical component of this pathway is the gradual phasing out of oil and coal power plants, which are among the highest contributors to carbon emissions. By reducing reliance on these fossil fuels, the sector will take significant strides toward decarbonization. Furthermore, the strategy includes the utilization of natural gas as a transitional fuel for thermal power plants, with plans to incorporate a hydrogen blend beyond 2035. The deployment of nuclear power is also featured as a key element in the energy portfolio, providing a reliable and low-carbon energy source. In addition to this, the importance of developing cross-border interconnections to enhance energy efficiency and security is also recognized as a key feature. This approach will pave the way to gradually increase the clean energy share of the country.

These combined efforts are designed to transform the power sector, enabling it to meet the ambitious goal of carbon neutrality by mid-century. By focusing on these critical elements, the plan not only aims to significantly reduce carbon emissions but also ensures that the power sector aligns with global climate targets.

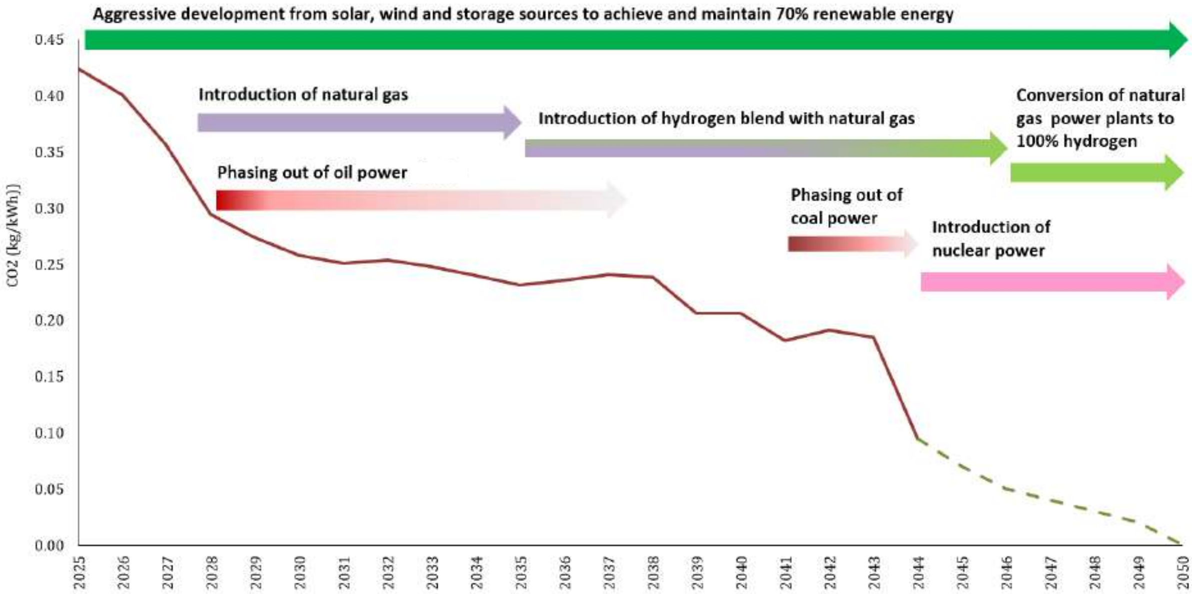


Figure 11.12 - Pathway to Carbon Neutrality in Electricity Sector

However, reaching carbon neutrality cannot be looked upon through the electricity sector alone and emission goals of the other sectors need to be aligned with it. Conservation of natural habitats, developing technology to draw greenhouse gases from the atmosphere as well as reducing the overall carbon emissions as a country are all important factors in the path to carbon neutrality. Activities such as green hydrogen production, EV charging for effective RE utilization, etc. will need the participation of many entities, including that of policy making.

CHAPTER 12
IMPLEMENTATION AND INVESTMENT OF THE BASE CASE

12.1 Present Status of Committed Power Plants in the Base Case Scenario

12.1.1 Renewable Energy Power Projects

a) Moragolla Hydro Power Project

Review of feasibility study and detail design has been completed in 2014 by Nippon Koei, joint venture with Nippon Koei India Pvt Ltd. Preconstruction work including detailed design and tendering commenced in July 2014. Funds from ADB were obtained for implementation of this project. The power plant is expected to be in operation by December 2024.

b) Solar Power Development

100 MW Siyambalanduwa Solar Plant will be developed as the first large scale solar park in the country and expected to be commissioned during 2026. Under the accelerated solar development program of the government, it is expected to commission 50 MW and 120 MW Solar Plants during 2025 and 2026 from Feed in Tariff scheme and tendering process. In addition, roof top solar development as distributed energy resource is progressing steadily with approximately 150 MW capacity additions annually.

c) Wind Power Development

50 MW Mannar Wind Plant which was initially planned to develop as an extension to the Mannar 100 MW wind plant, will be developed as a private power plant and expected to be commissioned by 2026.

Furthermore, 10 MW in 2025 and additional 40 MW wind power development from private sector will be connected in year 2026 under Feed in Tarriff scheme and tendering process.

12.1.2 Thermal Power Projects

a) First 350 MW natural gas fired Combined Cycle Power Plant

Construction of Gas Turbine has completed, and the operation of combined cycle operation is expected during 2025. This plant will have the dual fuel capability and operate on BOOT basis at Kerawalapitiya.

b) Second 350 MW natural gas fired Combined Cycle Power Plant

350 MW Natural Gas fired Combined Cycle Power Plant with dual fuel capability is in the pre-construction stage and is expected to operate on BOOT basis at Kerawalapitiya. The project is expected to be commissioned in 2026 in open cycle operation and in 2027 as combined cycle operation.

c) 200 MW natural gas fired Internal Combustion (IC) Engine Power Plant at Kerawalapitiya

200 MW IC Engine power plant is expected to be commissioned in 2028 and the procurement process has been initiated. The project is essential to absorb the increasing variations of renewable energy resources though its high start stop capabilities allowing high degree of flexibility to the system operator.

d) 130 MW natural gas fired Aero derivative Gas Turbines at Kelanithissa

CEB has planned to develop the 130 MW Gas Turbines at the Kelanithissa Power Station from international competitive bidding scheme. This power plant shall be able to operate flexibly and enhance the power system operational capabilities. In addition, it shall have the capability to support restoration of supply in case of an island wide power failure. The implementation of the power plant has been delayed and is expected to be operational by 2030.

12.1.3 Energy Storage Projects

a) 100 MW/100 MWh Battery Energy Storage System at Kollonawa

Based on initial studies conducted in the feasibility study funded by ADB for BESS projects, the project site Kolonnawa Grid substation was selected for the first BESS project based on transmission infrastructure limitation and importance for operation at load center. The project will provide pivotal services of fast frequency response services to prevent potential system failures and also act as a potential project to investigate the possibilities of system restoration and pilot scale energy shifting capabilities.

12.2 Present Status of Candidate Power Plants in the Base Case Scenario

A brief description of the current status of the candidate power projects on which the initial project activities were commenced are given below.

12.2.1 Renewable Energy Power Projects

a) Solar Power Development

The SEA and CEB has conducted initial studies to identify potential locations to develop large scale solar parks in the country. Large scale solar power parks are planned to be developed in Northern, North Eastern, Eastern, North Central, North Western and Southern regions of the country. Moreover, the Sri Lanka Sustainable Energy Authority has identified multiple potential reservoir locations to develop large scale floating solar projects. Development of these floating solar projects will be prioritized depending on the resource quality and associated development costs. The land acquisition and initial prefeasibility studies for these projects are being carried out by SEA.

b) Wind Power Development

The resources identification for wind power projects has recognized high potential wind power capacity in North western and Northern region of the country. Large scale on-shore wind power parks are planned to be established in potential locations such as north western and northern regions, mainly in Mannar, Pooneryn, Veravill and Karachchi. Furthermore, studies are being carried out by CEB to develop 100 MW in Silawathura.

With the limitations posed by the available wind potential in the country, the development of offshore wind power parks is also being considered.

12.2.2 Thermal Power Projects

a) Natural Gas based Gas Turbine/IC Engine Power Plants – West Coast

It has been identified that locating power plants near the load centres of the country has significant economic benefits. Thus, with the proposed establishment of LNG infrastructure facilities in Western region, Muthurajawela and Kelanitissa have been identified as potential locations for the next natural gas power plants.

b) Nuclear

Nuclear power generation option is also considered beyond year 2040 considering the lengthy gestation period associated with developing nuclear projects. The development of Pumped hydro storage power plant and HVDC interconnection are a pre requisite for the development of nuclear power for operating during off peak hours.

12.2.3 Energy Storage Projects

a) Battery Energy Storage (BESS) Projects

The first large scale battery is expected to be commissioned in 2026 and from year 2026 onwards, large scale Battery Energy Storage projects are proposed to be developed as standalone systems as well as integrated solutions coupled with large scale solar parks. The second major battery energy project is planned be established in the southern region with a capacity of 100 MW/ 400 MWh to cater the energy shifting requirements and fast frequency response services.

b) Pumped Storage Power Project

Pumped Storage Power Plants are to be used as a grid level energy storage. Two major potential sites were investigated at Aranayaka in the Maha Oya basin and at Wewathenna-Victoria reservoir. A feasibility study financed through the Asian Development Bank (ADB) to find out the best site to construct the first pumped storage power plant in Sri Lanka concluded that the 600 MW Maha Oya site was the best option for development of the first pumped storage power plant considering the costs, geological conditions, construction workability, and natural and social environments. All three units of 200 MW shall be developed as fixed speed pumping units to ensure sufficient inertia is provided during pumping mode.

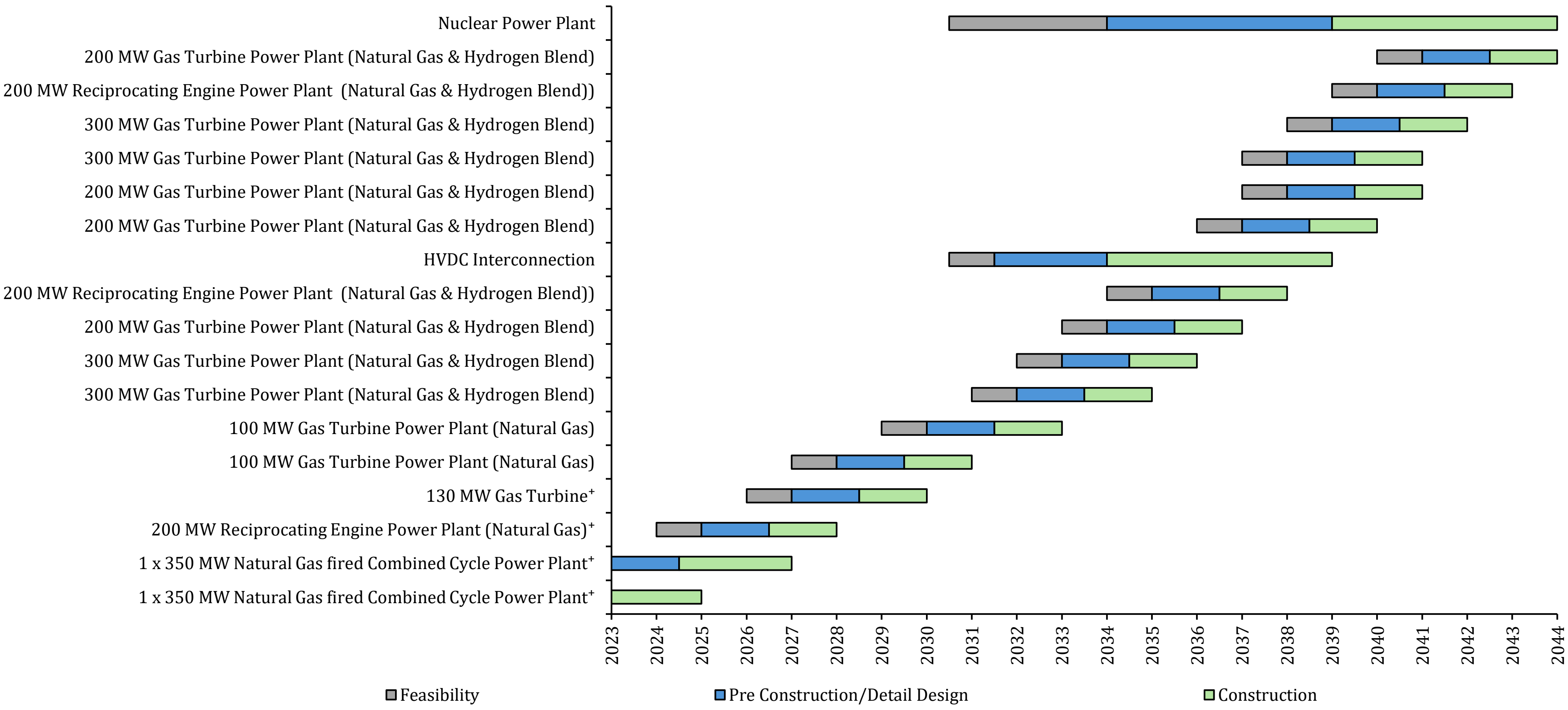
12.2.4 Interconnection Options

HVDC interconnection between the Indian and Sri Lankan electricity grids through a 2 x 500 MW HVDC interconnection from Madurai New (India) to Mannar (Sri Lanka) is being explored as a potential option beyond the year 2030.

12.3 Implementation Schedule

The implementation of power projects consists of three phases; feasibility, pre-construction and construction phase. Some sub activities during these phases include land identification and allocation, obtaining environmental approvals, procurement procedures and securing of funding and finances. In order to implement a project on time, it is necessary to have support from all relevant government institutions and other involved public stakeholders.

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plant and reliability during operation and maintenance. The implementation schedule for committed and proposed major thermal power plants and interconnection options in the Base Case 2025-2044 are shown in Figure 12.1. The implementation schedule for large scale wind and solar projects are shown in Figure 12.2. The implementation schedule for committed and proposed storage projects in the Base Case 2025-2044 are shown in Figure 12.3.



+ Committed Plants

Figure 12.1 - Implementation Plan of Thermal and HVDC Interconnection Projects 2025-2044

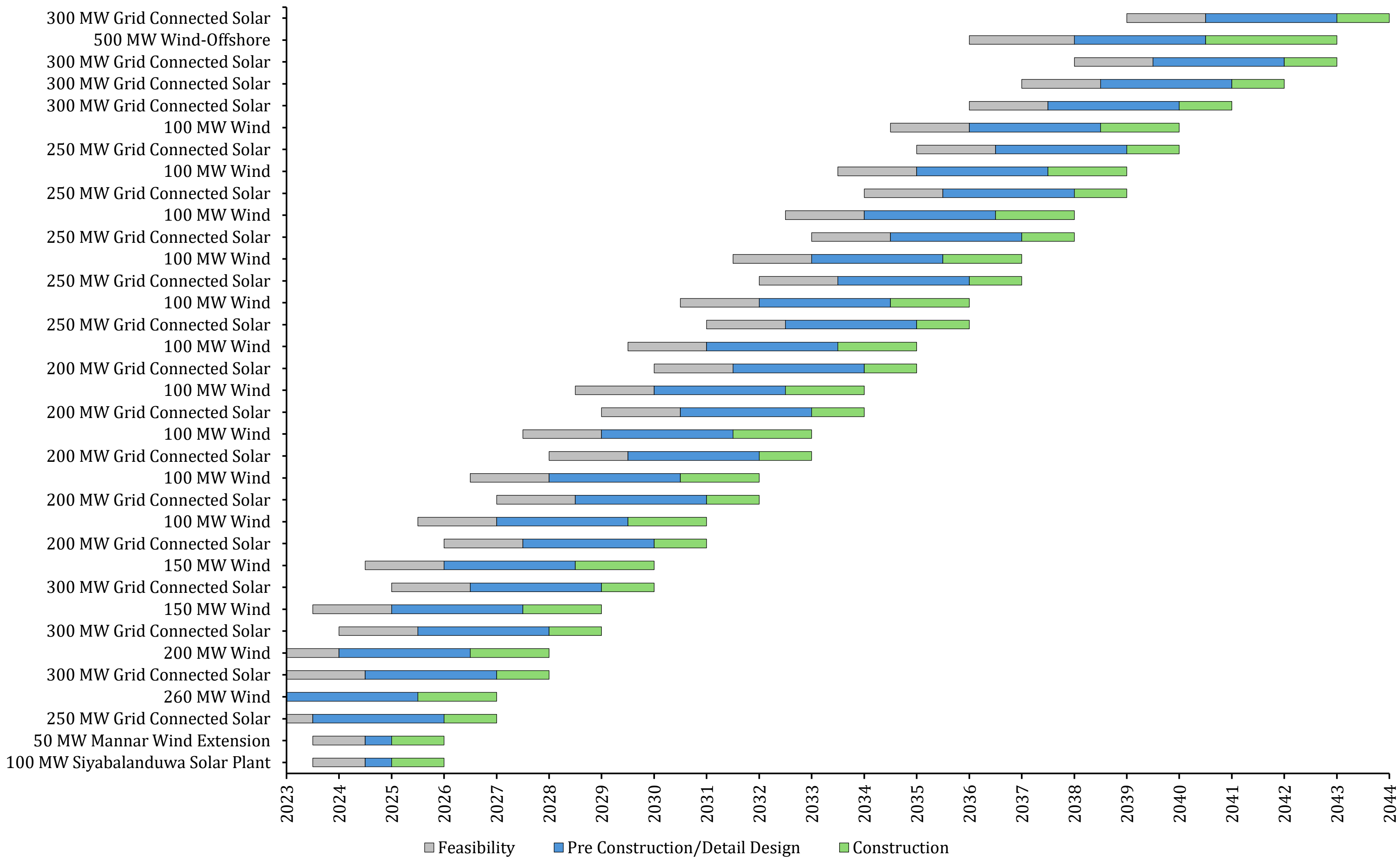


Figure 12.2 - Implementation Plan of Large Scale Wind and Solar

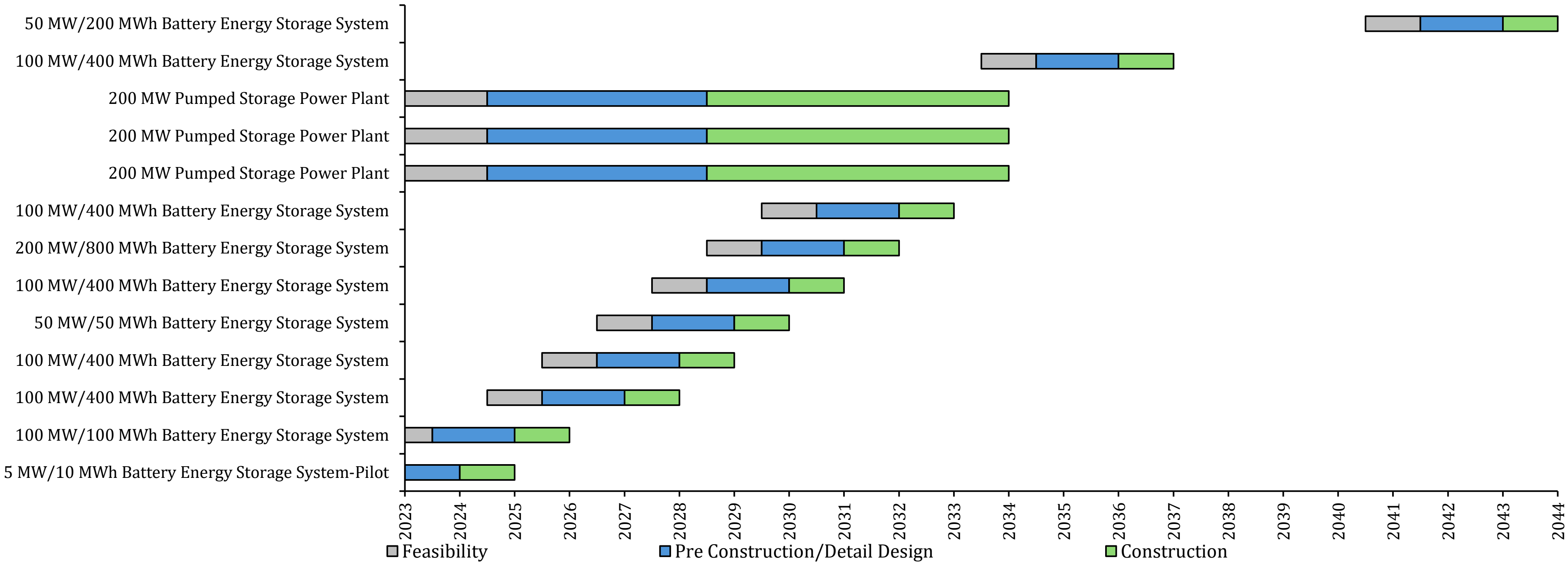


Figure 12.3 - Implementation Plan of Storage Projects 2025-2044

12.4 Investment Plan for Base Case Scenario and Financial Options

12.4.1 Investment Requirement for Base Case Scenario 2025-2044

Technology wise non-discounted investment requirement which shows the actual upfront capital expenditure requirement of each year in the Base Case scenario 2025-2044 is shown in Figure 12.4. The cost details of the investment requirement for thermal power projects and major wind, solar and storage developments are given in Annex 12.1 and 12.2 respectively. Tabulated annual investment costs include only the plant-by-plant pure construction cost.

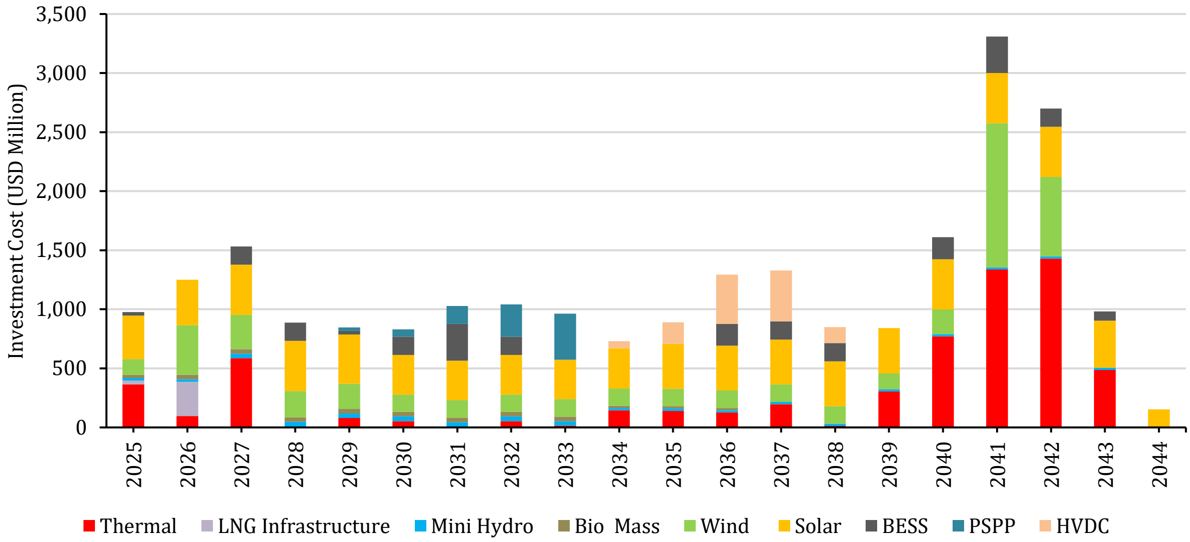


Figure 12.4 - Investment Requirement for Base Case Scenario 2025 – 2044

12.4.2 Annualized Investment Cost for Base Case Scenario 2025-2044

Annualized investment cost requirement disbursed over the financial lifetime of each project in Base Case Plan 2025-2044 is graphically shown in Figure 12.5.

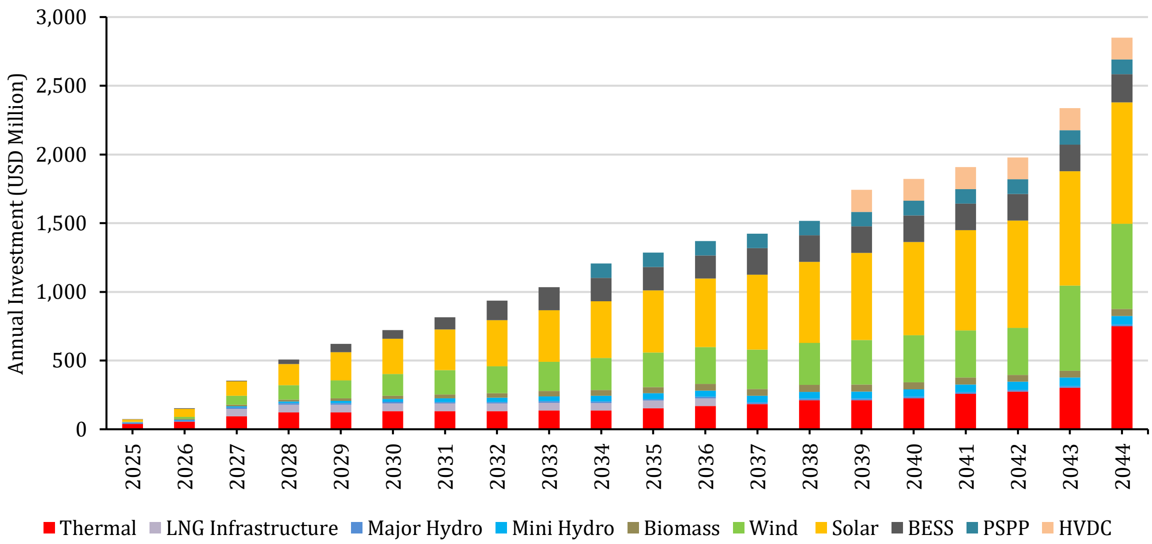


Figure 12.5 – Technology Wise Investment Plan for Base Case Scenario 2025 –2044

12.4.3 Financial Options

Timely investment on the power generation projects is highly important to be in line with the commissioning years of the planned power plant developments, although this may be challenging due to the economic situation of the country at present.

Capital investment required for the new power generation facilities could be considered in the form of GOSL/CEB funds, Private funds (such as Independent Power Producers - IPP and Joint Ventures - JV) and Public and Private Partnerships (PPP). The funding could be obtained through sources such as Official Development Assistance (ODA), Export credit, Local Commercial Loans, Concessionary loans, issuance of Green Bonds, Grants by other countries and Government to Government facilities.

The financial terms such as interest rate, commitment fee, exposure fee, grace period and loan repayment period of these funding options would be determined based on,

a) Financial performance of the country
b) Financial performance of the utility
c) Granting of government guarantee
d) Credit risk ratings
e) Government to Government Concessions, etc.

Most favourable scheme out of above funding options should be selected based on the financial evaluation. Financial evaluation aims at evaluating the return on investment from a viewpoint of an implementing agency. Financial evaluation of individual projects shall be performed considering financial indicators, which determine the viability of individual project. The financial indicators include,

a) Internal Rate of Return (IRR)
b) Financial Internal Rate of Return (FIRR)
c) Return on Equity (ROE)
d) Weighted Average Cost of Capital (WACC)
e) Levelized Cost of Energy (LCOE)

IRR & FIRR should be compared with prevailing financial market rates in order to evaluate the viability of the project. ROE is an indicator of the equity providers' expectation on return. The WACC is an estimation of the expected costs of a projects' all financing sources. This indicates the rate that a project/company is expected to pay on average to all its capital sources including required rate of return demanded by equity holders (cost of equity financing) and debt obligations (cost of debt financing). LCOE is a useful indicator to determine whether to invest for a power generation project. This will vary depending on the type of project and it is usually taken as a representation for the average price that the generating asset must receive in a market to break even over its lifetime.

CHAPTER 13
CONTINGENCY ANALYSIS

13.1 Background

This chapter analyses the impact of both controllable and uncontrollable risk events, which could lead to inadequacy of supply to meet the capacity and energy demand in the immediate future years from 2025 to 2029 in the Base Case scenario. The Contingency Analysis focuses on identifying the main risk events, which are given below:

1. Variation in hydrology
2. Variation in demand
3. Delays in implementation of power plants
4. Long outage period of a major power plant
5. Restriction of fuel supply

13.2 Risk Events

13.2.1 Variation in Hydrology

Hydrology is one of the significant risk events that could lead to energy supply shortage. Table 13.1 depicts the annual expected energy output of hydro system for the five hydro conditions, availability of adequate capacity and energy supply to meet the demand in the driest hydrological condition is important.

Table 13.1 - Expected Annual Major Hydro Energy Output Range of Five Hydro Conditions

Hydro Condition	Expected Annual Energy (GWh)
Very Dry	3,500- 4,000
Dry	4,000- 4,700
Average	4,700-5,300
Wet	5,300-6,000
Very Wet	6,000-6,500

13.2.2 Variation in Demand

Variation in demand from the base demand projection is considered as an uncertainty. Difference of annual energy and peak demand from 2025 to 2029, for both high demand and low demand scenarios compared to the base demand forecast is shown in Figure 13.1 and Figure 13.2. Assessment of the adequacy of capacity and energy supply to cater the high demand scenario is an important consideration.

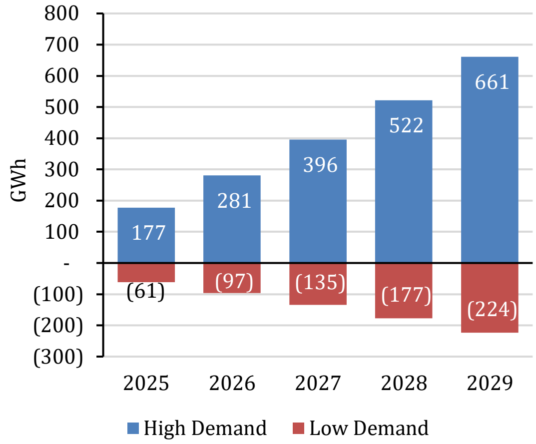


Figure 13.1 –Annual Energy Demand Variations

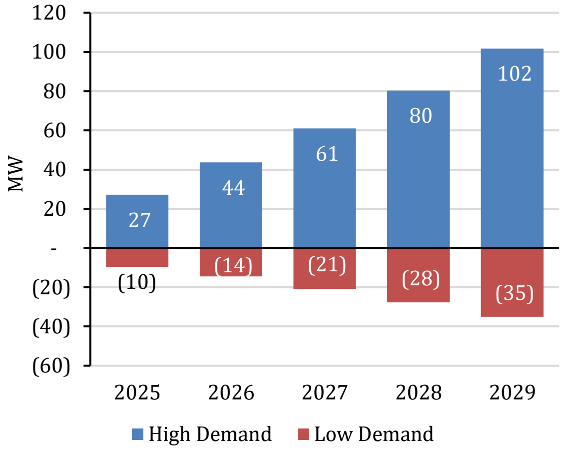


Figure 13.2 –Annual Peak Demand Variations

13.2.3 Delays in Implementing Power Plants

Timely implementation of committed power plants on schedule is critical to avoid capacity and energy shortfalls in short term. However, unexpected deviations can occur in power project implementation phase and the consequences of such implementation delays on the capacity and energy requirement is considered in this analysis. Possibility of a one year delay is considered for each major pipeline project under eight different implementation delay cases. Major thermal power projects, extensions of existing thermal power projects and energy storage projects are considerd with one year implementation delay for evaluation of contingencies. The implementation delay cases as depicted in Table 13.2 are evaluated to capture most probabilistic implementation delayes in future.

Table 13.2 - Implementation Delay Cases for Major Pipeline Projects

	Major Pipeline Project					
	ST of 1st 350 MW NG CCY	**Sapu A, Sapu B and Barge Extensions**	**(GT+ST) of 2nd 350 MW NG CCY**	**Gas Engine 200 MW**	**BESS 100 MW**	**BESS 100 MW**
Base Case	**2025**	**2026**	**2027**	**2028**	**2028**	**2029**
Case 1	2026	2026	2027	2028	2028	2029
Case 2	2025	2027	2027	2028	2028	2029
Case 3	2026	2027	2027	2028	2028	2029
Case 4	2025	2027	2028	2028	2028	2029
Case 5	2025	2026	2028	2029	2028	2029
Case 6	2025	2027	2028	2029	2028	2029
Case 7	2025	2026	2027	2029	2029	2030
Case 8	2026	2027	2028	2029	2029	2030

13.2.4 Long Period Outage of a Major Power Plant

Outage of a major power plant for a prolonged time period during dry season is also considered as a major risk event. For the contingency analysis, outage of one unit of Lakvijaya Coal Power Plant during the dry season in first four months from January to April was considered. Details of this risk event is given in Table 14.3.

Table 13.3 - Details of Risk Event Outage of a Major Power Plant

Parameter	Description
Period	Four months (January – April) in each year
Loss of Capacity	270 MW
Loss of Energy	600 GWh per year

13.2.5 Restriction of Fuel Supply

There has been an increased risk of supply of fuel to major thermal power plants in the recent past due to the prevaling foreign currency shoratge. Considering any disruptions that could affect supply chains, the worst case scenario of restriction of fuel to all oil, gas and coal plants are considered for contingncy analysis.

For contingency analysis, limits were imposed on the amount of fuel that can be supplied for the operation of thermal power plants as given in Table 13.4.

Table 13.4 - Details of Risk Event Restriction of Fuel Supply

Event	Fuel	Fuel Supply Limit
1	Fuel Supply Limit (Diesel)	34,000 Barrels per month (20% Reduction)
2	Fuel Supply Limit (Furnace Oil)	90,000 Barrels per month (20% Reduction)
3	Fuel Supply Limit (Naptha)	97,000 Barrels per month (20% Reduction)
4	Fuel Supply Limit (Natural Gas)	0.2 Million tons per year (20% Reduction)
5	Fuel Supply Limit (Coal)	2 Million tons per year (10% Reduction)

For evaluation of contingencies, two cases were evaluated considering restriction of the supply of oil and gas only and restriction of the supply of oil, gas and coal.

Case 1: Restriction on oil and gas (simultaenous occurance of events 1,2,3 and 4 in the Table 13.4)

Case 2: Restriction on all fuels of oil, gas and coal (simultaenous occurance of all five events in the Table 13.4.)

13.3 Evaluation of Contingencies

In this contingeny analysis, initially the single occurrence of above mentioned five risk events were considered at first and thereafter, simultatious occurrence of several events were analysed to identify the short term energy and capacity shortage.

The firm capacity during the critical period of each year in the Base Case scenario as shown in the Table 13.5 is taken as the reference for the contingency events. Critical period is the period where the difference between peak demand and the firm capacity becomes minimum. This occurs during the night peak of the dry seaon for the period from 2025-2029.

Table 13.5 - Firm Capacities in Critical Period as in the Base Case Scenario

Firm Capacity	**2025**	**2026**	**2027**	**2028**	**2029**
Major Hydro Capacity (MW)	918	918	918	918	918
Thermal Capacity (MW)	2,077	2,174	2,274	2,550	2,550
ORE (MW)	61	66	90	106	118
Storage (MW)	-	-	-	80	160
Total Firm Capacity MW (Critical Period)	**3,056**	**3,158**	**3,282**	**3,654**	**3,747**
Night Peak Demand MW (Critical Period)	**2,696**	**2,824**	**2,959**	**3,101**	**3,250**

Capacity deficit risk is the inability of firm capacity to meet the peak demand in the critical period with minimum reliability requirement. The Energy Deficit risk is the possibilty that the avaible plants will not be able to provide the total energy requirement.

13.3.1 Single Occurrence of Risk Events

The five risk events have potential to cause inadequate supply capability of the system. The summary of impact of other single occurance of risk events is shown in Table 13.6 below.

Though the variation of hydrology is significant, since capacity expansion is optimized considering the driest hydro contition, impact of the hydrology variation is already taken in to account in preparation of the Base Case scenario. Secondly, the variation in demand is also performed as a sensitivity (under Chapter 10). Thirdly, although the event of power plant implementation delays has a high likelihood, moderate impact can be expected. The outage of a largest unit during critical periods could be managed with the other remainng power plants if they are commisioned on time. The restriction of fuel supply during the crtitical months of the year is the most severe risk event which poses substantial energy deficit risks.

Table 13.6 - Impact of Single Occurrence of Risk Events

	Risk Event	Capacity Deficit Risk	Energy Deficit Risk	Remarks
1	Dry Hydro Condition	No	Low	No capacity deficit with the planned capacity addition of the Base Case scenario. Energy requirement in the very dry hydro condition can be catered with the planned capacities in the Base Case scenario (Table 10.1 of Chapter 10)
2	High Demand	No	Low	Even in the expected high demand scenario, capacity deficit does not occur. The minimum reliability requirment in case of high demand could be maintained within initial 5 years with the same capacity additons of the Base Case scenario.
3	Plant Implementation Delay	Low	Low	Only in the event of simultaneous delay in all the extensions of power projects and the second combined cycle power plant (Cases 4,6 & 8 in Table 13.2), there is a risk of a 150 MW capacity deficit in 2026. In all other cases no capacity deficit is observed. However, it is unikely event that all extension projects are delayed simultaneously.
4	Outage of a Major Power Plant	Low	Low	A capcity deficit of 20 MW is observed, to maintain the minimum relibility criteria during the night peak of the dry season in year 2027. However, there is adequate capacity to resolve occurance of any severe capacity deficit risk or energy deficit risk in the other years.
5	Restriction of fuel supply	High	High	Restriction of fuel supply poses a severe risk of energy deficit mainly during the months from February to April. The monthly energy deficit in Case 1 (restriction of oil and gas supply), can reach upto 18% of monthly energy demand. This can further aggrevate upto 29% in Case 2 (restriction of oil, gas and coal supply)

The detailed Energy Deficit Risk in monthly resolution is presented in Annex 13.1 It should be noted that majoirty of the risk occurs during the months from February to April of the year, and appropriate early action should be taken by considering these patterns.

13.3.2 Simultaneous Occurrence of Several Risk Events

Several contingency events are analysed to identify the severity of simultanious occurance of these events for period from 2025 to 2029 and mitigation measures are required where necessary.

a) Contingency Event 1 - Dry Hydro Condition and Delays in Power Plant Implementation

The both events of worst hydro condition and the power plant implementation delays were taken as the first contingency event. The parameter variations given in section 13.2.1 and 13.2.3 were taken as the basis for the analysis. In terms of mitigating this risk, possibility of providing the energy deficit from avalilable power plants was studied relative to the Base case scenario. The additional capacity deficit and the risk of energy deficit compared to the Base case scenario is indicated in the Table 13.7 below.

Table 13.7 - Assessment of the Additional Capacity Deficit and the Risk of Energy Deficit Compared to the Base Case Scenario due to Contingency Event 1

	2025	2026	2027	2028	2029
Risk 1: Dry Hydro Condition **Risk 3: Delay in Plant Implementation (Delay Case 8 in Table 13.2)**					
Capacity Deficit [Energy Deficit Risk]	- [Low]	150 MW [Low]	- [Low]	- [Low]	- [Low]

This contingency event has an impact on the adequate supply capacity of the system in 2026. Additional capacity is required to meet the electricity demand adequately while maintaining the minimum relaibility level in 2026. While it is unlikely that all extension projects will be delayed simultaneously, the timely implementation of major pipeline projects is crucial to avoid any possible capacity and energy deficits.

b) Contingency Event 2 - Dry Hydro Condition, Delays in Power Plant Implementation and Outage of one Unit of Lakvijaya Coal Power Plant

An adverse contingency event with the loss of one unit of Lakvijaya Coal Power Plant simultaniously with other two risk events of section (a) above is considered for the analysis. The unit outage is assumed to occur in the dry season during first four months of the year. It is observed that capacity deficit can occur for a short period under this contingency event. The capacity deficit and the risk of energy deficit compared to the Base Case scenario is indicated in the Table 13.8 below.

Table 13.8 - Assessment of the Additional Capacity Deficit and the Risk of Energy Deficit Compared to the Base Case Scenario under Contingency Event 2

	2025	2026	2027	2028	2029
Risk 1: Dry Hydro Condition **Risk 3: Delay in Plant Implementation (Delay Case 8 in Table 13.2)** **Risk 4: Major Unit Outage (Outage of one unit of Lakvijaya Power Plant in Jan- April)**					
Capacity Deficit [Energy Deficit Risk]	75 MW [Low]	420 MW [Low]	120 MW [Low]	75 MW [Low]	- [Low]

c) **Contingency Event 3 – Dry Hydro Condition, Delays in Power Plant Implementaion and Restricted Fuel Supply**

The events of dry hydro condition, power plant implementation delays and restriction of fuel supply were taken as the third contingency event. This is an adverse contingency event, that has a likelihood of occuring during any economic crisis of the country considering past events. Only the major implementation delay cases have been conisdered for analysis, and fuel supply restriction is conisdered only for oil and gas based power plants.

The capacity deficit and the risk of energy deficit of contingency event 3 compared to the Base Case scenario is indicated in the Table 13.9 below.

Table 13.9 - Assessment of the Additional Capacity Deficit and the Risk of Energy Deficit Compared to the Base Case Scenario under Contingency Event 3

	2025	2026	2027	2028	2029
Risk 1: Dry Hydro Condition					
Risk 3: Delay in Plant Implementation (Delay Case 8 in Table 13.2)					
Risk 5: Restricted Fuel Supply (Case 1 – Restriction on oil and gas)					
Capacity Deficit[1]	-	150 MW	-	-	-
[Energy Deficit Risk]	[High]	[High]	[High]	[High]	[High]

[1] Capacity Deficit Risk will be even higher due to fuel shortage as it cannot be precisely quantified.

d) **Contingency Event 4 - High Demand, Dry Hydro Condition, Delays in Power Plant Implementaion and Restricted Fuel Supply**

The risk event considers the possibility of a demand increase beyond the base demand projection under worst hydro condition with delays in power plant implementation and fuel supply been restricted. The demand increase beyond the base demand projection has a relatively low likelihood due to the unexpected economic situation of the country but the level of uncertainty related to the demand is very high. The capacity deficit and the risk of energy deficit compared to the Base Case scenario is indicated in the Table 13.10 below.

Table 13.10 - Assessment of the Additional Capacity Deficit and the Risk of Energy Deficit Compared to the Base Case Scenario under Contingency Event 4

	2025	2026	2027	2027	2028
Risk 1: Dry Hydro Condition					
Risk 2: High Demand					
Risk 3: Delay in Plant Implementation (Delay Case 8 in Table 13.2)					
Risk 5: Restricted Fuel Supply (Case 1 – Restriction on oil and gas)					
Capacity Deficit[1]	-	195 MW	-	-	-
[Energy Deficit Risk]	[High]	[High]	[High]	[High]	[High]

[1] Capacity Deficit Risk will be even higher due to fuel shortage as it cannot be precisely quantified.

13.4 Conclusion

a) The individual risk events have varying impacts on the Base Case scenario. The driest hydrology condition has already been captured in the preparation of the Base Case scenario in the planning studies. The variation in demand is also performed as a sensitivity (presented in Chapter 10). The possibility of demand increase beyond the base demand projection is relatively low due to the present economic situation of the country, but the level of uncertainty related to the demand is very high. Thirdly, the power plant implemnetation delays pose moderate risk and likelihood of occuring is high. Outage of a largest unit during critical periods of the year can be managed if other power plants are implemented on time. The restriction of fuel supply during the crtitical months of the year is the most severe risk event which poses significant energy deficit risks and should be avoided.

b) In the case of simultaneous occurrence of contingency events, the likelihood of contingency event 1 is high. However, it can be managed with avaiable resources except in year 2026 if all the extensions of power projects and the second combined cycle power plant are delayed. The likelihood of contingency event 2 is moderate but the impact can be very high if a major unit outage takes place during the driest period when the project implementation is delayed. Therefore, it is important to ensure the timely implementation of the planned projects as well as the availability of the major thermal power plants in operation. The likelihood of contingency event 3 is moderate but the impact can be severe if fuel supply restrictions takes place during the driest period when the planned project implementation is delayed. Therefore, it is important to ensure the availability of fuel as well as timely implementtaion of the planned projects. The likelihood of contingency event 4 is relatively low as demand increase beyond the base demand projection in the initial years is low. But in the event of demand increase takes place while power plant implementation delays and fuel shortages are present, severe capacity and energy deficits can be experienced during 2025 to 2029 period.

c) Implementation delays of renewable energy projects have not been considered in this contingency analysis as their contribution towards the night peak in critical period is minimal. However, delays in implementation of renewable projects would further aggravate the situation in the event of restricted fuel supply situation. it is important to monitor and ensure the timely implementation of all large scale and small-scale renewable energy projects to obtain the expected energy contribution.

d) The short term capacity deficits identified in the Tables 13.7, 13.8, 13.9 and 13.10 are based on inputs used for the planning studies and the exact capacity requirement and the period shall be determined at the time of procurement of such capacity, through detailed short term analysis, taking into consideration the prevailing system situation at that time.

e) The possibility of utilizing the available generating capacities with lapsed contracts as well as other short term alternatives shall be considered as appropriately to meet short term requirement in most economically advantageous terms within the legal framework of the country.

f) The impact of the above contingency events on the cost of generation as well as on the economy as a whole is high because short term capacity deficits are avoided using short term alternatives, that are expensive. Therefore, it is a nationally important task to implement the planned pipeline projects as well as the planned transmission development on time to ensure reliable and economic supply of electricity.

CHAPTER 14
RECOMMENDATIONS OF THE BASE CASE SCENARIO

14.1 Background

As discussed in Chapter 10, Base Case scenario is developed to achieve 70% of renewable generation by 2030 with a mix of thermal generation technologies and storage options to complement renewables. Timely implementation of proposed power plants is crucial to avoid capacity shortages, energy shortages and high cost alternative generation in the future.

Economies of renewable energy and advancement in renewable and storage technologies are evolving rapidly around the world. The rolling generation expansion plans prepared by CEB once in two years are intended to capture such changes in subsequent planning cycles. The generation expansion envisioned for the last ten years in the planning window is relied on the present up-to-date information whereas such can undergo changes in the future, with the advancement of technologies.

Accordingly, the recommendations for the Base Case scenario, pertaining particularly to the first ten years of the planning horizon are given below with special emphasis on the importance of timely implementation of power plant projects to secure, affordable and reliable supply of electricity.

14.2 Recommendations for the Base Case Scenario

Major recommendations for the Base Case scenario are as follows.

1. Development of Renewable Energy

   Base Case scenario 2025-2044 has identified a cumulative capacity of 5,335 MW of ORE to be developed within the first ten years of the planning horizon. This includes development of 3,720 MW of solar, 1,260 MW of wind, 170 MW of mini hydro and 185 MW of biomass power capacities in the first ten years. Timely implementation of projects to achieve these ORE capacities as per the schedule is important to cater to the growing demand while achieving policy targets and climate change obligations. The locations of ORE power plants should be prioritized based on the plant factors, land availability and cost of transmission network. During initial years priority shall be given to locations in which resource potential and grid interconnection capability are available. Formalities and procedures related to land acquisition, environment clearance, etc. have to be reviewed in order to expedite the implementation of ORE projects. It is recommended to streamline renewable energy development procedures to ensure faster implementation as well as strict compliance to interconnection codes. All new medium to large scale ORE power plants should have the operational, technical and contractual capability for curtailment when necessary. Hence, steps shall be taken to procure at least 90% of the new power plants developed as grid connected solar projects and wind projects shall be dispatchable from National System Control Centre.

2. Commissioning of Natural gas based Combined Cycle power plants on time

   The first two 350 MW Natural gas based Combined Cycle power plants which are at the construction phase and project development phase should be commissioned to operate on combined cycle mode by the years 2025 and 2027 respectively. These Power plants shall be technically, operationally and contractually capable of being operated regularly between open cycle and combined cycle modes. It is required that the second combined cycle power plant have lower minimum load level capabilities, higher ramp rates and shorter start up time in par with present industry performance levels.

3. Availability of Liquefied Natural Gas (LNG)/Natural Gas (NG) and Infrastructure

   Natural gas based Power plants will initially operate on oil and the operation from natural gas is expected from year 2027 onwards with establishment of necessary infrastructure. Therefore, required LNG infrastructure with associated natural gas distribution network should be developed in line with this time target considering it as a national priority project.

   It is required to ensure that LNG procurement contracts are made to minimize the 'Take or Pay' risks because such commitments can influence the dispatch decisions which will result in low economic benefits and inability to meet the national renewable energy targets.

4. Development of Flexible Thermal Generation to Complement High VRE Integration

   Due to the intermittent and variable nature of VRE, the power system needs to have sufficient flexible power sources to ensure system stability and reliability. These flexible power plants should possess the fast startup, fast ramping and deloading capabilities to support the power system to manage the daily net load fluctuations typically seen with high VRE levels.

   The first flexible generation power plant introduced is the IC Engine power plant proposed at Kerawalapitiya for year 2028. Subsequently 130 MW Gas Turbines are expected to be commissioned at Kelanithissa in year 2030. This power plant would additionally provide services for quick restoration of Colombo power supply in the event of an island wide power failure

   All the Gas Turbine and IC Engine power plants proposed have been included in the base case scenario to fulfil this specific flexibility requirement of the system. Therefore, these proposed power plants should have superior operational flexibility with capability of multiple start-stops without sacrificing their equivalent running hours. Furthermore, these plants will provide the requirement of spinning and non-spinning reserves of the system. These power plants should also have high part load efficiencies and should have minimum start up and shut down times.

   These power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply. The choice of secondary fuel shall be decided at procurement stage from suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms. Furthermore, considering the policy requirement on carbon neutrality goals, all future power plants should have the capability to operate from synthetic fuels such as hydrogen.

5. Development of Battery Energy Storage System (BESS)

   With the high penetration of variable renewable energy, battery energy storage capacities are introduced for the purpose of fast frequency response services and energy shifting requirements to support renewable energy integration. As first step, a 100 MW/100 MWh BESS is planned to be commissioned at Kollonawa Grid Substation by year 2026. The battery capacity is planned to gradually increase up to 305 MW by 2030. This capacity could either be developed as stand-alone or co-located with large scale solar parks with dispatch capability from national system control centre. The BESS utilized for energy shifting would require to have minimum 4-hour duration storage, and the possibility of stacking up with other ancillary services to the same are to be evaluated.

6. Development of Pumped Storage Power Plant

   Implementation of the planned 3 x 200 MW Maha Oya pumped storage hydro plant is critical as a long term measure to enhance the flexibility and security of the system with high shares of renewable energy technologies. This energy storage technology shall facilitate projected variable renewable energy (wind & solar) absorption by reducing the curtailments of energy generation. In addition, the pumped storage units shall provide the much necessary system inertia in pumping mode which is critical during day time hours. The power plants will operate as a peaking power plant by minimizing high-cost thermal generation. All three units of the PSPP is expected to be commissioned during 2034. It is necessary to complete the detailed feasibility study by end of 2024 and secure funding and finance for the project by year 2026 so that power plant could be commissioned on time.

7. Establishment of Renewable Energy Desk with Resource Forecasting System

   The early introduction of a "Renewable Energy Desk" to the National System Control Centre is essential to separately manage renewable energy capacities that are going to be integrated in large proportions. The Renewable Energy Desk shall have main functions to cater the following.

   a) Monitoring and supervisory controlling facilities of renewable energy plants and storage facilities to the National System Control Centre.
   b) Renewable energy forecasting system with intra-hour, intra-day and day-ahead timeframes which is vital to manage the uncertainty in maintaining supply and demand balance.
   c) Renewable energy scheduling to transparently allocate generation and curtailment among different power projects.

   In order the facilitate smooth operation of National system control centre tools equipped with net demand assessment, ramping and flexibility assessment, reserve requirement assessment with DPR and inertia monitoring and assessment are required to be incorporated.

   The development of Renewable energy desk is expected phase by phase and major components are required to be completed by year 2026 to ensure that system is capable to operate with high VRE integration levels.

8. Development of Transmission Infrastructure

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plants with the expected reliability. Securing funding and timely implementation of these critical transmission infrastructure projects is essential for commissioning of power projects. The major developments identified for transmission infrastructure to evacuate power from power projects is summarized in Table 14.1.

Table 14.1 - Essential Transmission Development Infrastructure

Power Project		**Required Completion time**	**Required Major Transmission Development**
Kerawalapitiya Thermal Complex	1st 350 MW Natural Gas CCY	2025	– Construction of Veyangoda-Kirindiwela-Padukka 220 kV transmission line – Construction of Kotmale-New Polpitiya 220 kV transmission line – Construction of Kerawalapitiya 220 kV switching station – Construction of Kirindiwela 220 kV GSS switching station
	2nd 350 MW Natural Gas CCY	2027	– Construction of Kerawalapitiya - Port 2nd 220kV Cable
	200 MW Natural Gas IC Engine	2028	
100 MW Siyambalanduwa Solar Park		2026	– Construction of Siyambalanduwa- Monaragala 132kV transmission line – Reconstruction of Medagama - Ampara 132 kV transmission line
Southern Renewable Energy Zone Development	Phase I Solar	2027	– Construction of Matara – Hambantota 132 kV transmission line
	Phase II Solar	2030	– Construction of Hambantota – Monaragla 220 kV transmission line
North Eastern Renewable Energy Zone Development	Phase I Solar 50 MW	2027	– Construction of Kapplturei – Sampoor 220 kV transmission line (132kV Operation)
	Phase II Solar	2029	– Construction of New Habarana – Kappalturei 220 kV transmission line – Construction of Kappalturei – Trinco 2 220kV transmission line

Power Project		Required Completion time	Required Major Transmission Development
North Western Renewable Energy Zone Development	Phase I Wind 60 MW	2028	– No major transmission infrastructure
	Phase II Wind 60 MW	2032	– Reconductoring of 132kV Puttlam – Chillaw transmission line with a high capacity conductor
Northern Renewable Energy Zone Development	Phase I-Ext Wind 50 MW Mannar	2026	– No major transmission infrastructure
	Phase II Wind 250 MW Mannar	2027	– Reconductoring of 220kV Mannar – Vauniya transmission line with a high capacity conductor
	Phase III Wind Silawatura	2032	
	Wind Pooneryn	2028	– Construction of Pooneryn – N Collector 220kV transmission Line – Vauniya 220kV development – Vauniya- N Collector 220kV transmission line
	Solar & Wind	2028-2032	– Construction of New Habarana – Vauniya – N Collector 400 kV transmission line – Construction of N Collector, Vauniya and New Habarana 400 kV switching station – Construction of New Habarana – Maha – Kirindiwela 400 kV transmission Line and Construction of Maha 400 kV Switching station
Eastern Renewable Energy Zone Development	Phase I Solar 100 MW	2027	– No major transmission infrastructure
	Phase II Solar	2032	– Construction of New Habarana – Valachchenai 220 kV transmission line
Pumped Hydro Storage Development		2034	– Construction of New Habarana – Maha – Kirindiwela 400 kV transmission line and Construction of Maha 400 kV Switching station

Information provided above are based on initial projections and exact transmission infrastructure requirement shall be decided after finalizing locations of all power projects. Hence the scope of collector grid substations and relevant power plant interconnections are excluded. Due to the interdependencies of certain transmission infrastructure, the development of transmission should be prioritized to align with the earliest occurrence of each project.

9. Securing of Land and Transmission Line Corridors

In the power sector, identification and securing of the lands for future power plants and associated infrastructure is crucial. Therefore, locations for establishing power generation facilities and related transmission corridors which interconnect such facilities to the national grid should be identified in advance and secured considering this as a national priority. Potential locations identified at present for future power generation projects are given in Table 14.2.

Table 14.2 - Potential Locations for Future Power Generation Projects

Power Project	**Identified Potential Locations**
Solar Park	Northern, North Eastern, Eastern, North Central, North Western and Southern regions (Hambantota, Trincomalee, Monaragala, Valaichenai, Kilinochchi etc.)
Wind Park	Northern & North Western Regions (Mannar, Pooneryn, Veravil, Karachchi, Puttalam)
Pumped Hydro Storage	Maha Oya -Aranayaka in Kegalle Victoria-Wewathenna in Kandy
Battery Energy Storage	Integrated with large solar parks Standalone Utility Scale Projects (Western, Southern and North Central region)
Natural Gas Power Projects	Kerawalapitiya, Muthurajawela

10. Development of Distributed Energy Resources

Integration of large capacities of Distributed Energy Resources (DER), mainly through rooftop solar PV schemes shall be an integral requirement to achieve government policy targets. It is necessary to enable proper mechanisms to facilitate accelerated growth of DER while minimizing adverse effects on the network with following recommendations.

a) It is considered to mandate operation of all future and existing (if possible) Solar PV Inverters of MV and LV connected schemes to operate on Voltage Control Mode.

b) Deploying of smart meters for solar PV connections and installation of communication system to provide comprehensive visibility at Distribution Control Centres and aggregate clusters visibility at National System Control Centre is also recommended.

c) Evaluating the capability of installing on-load tap changers for the existing distribution transformers with two tap positions to avoid overvoltage during daytime and undervoltage during night time as an interim measure.

d) Development of geospatial feeder wise Hosting Capacity Map, to concentrate investments at correct locations, to be in par with distribution network expansions.

DER development is mainly consumer driven and if they are expected to absorbed at higher capacities than envisioned in Base Case scenario, they are required to be incorporated as dispatchable power plants with necessary grid support services.

11. Review of Interconnection and operating codes, planning codes, policies and regulations

    It is recommended to periodically review and upgrade the existing interconnection and operating codes, planning codes and regulations based on detailed studies and up-to-date industry practices. Specific attributes that require periodic reviewing are as follows.

    a) Reviewing the present operating reserve policy of system operation, with dynamic upward and downward requirements that provide additional regulation for the planned renewable energy capacities is required.
    b) Enhancing the grid support features of variable renewable energy projects including enhanced Ride through capabilities, Ramp Rate Control functions, active power control, etc. through codes and regulations is mandatory to proceed with the planned renewable energy development program.
    c) Formulation of curtailment policies and contracts that facilitate necessary mechanisms to optimally operate the power system.
    d) Reviewing the planning codes, and establish suitable parameters and matrices to be adopted for reliability criteria that reflect operation of a high VRE integrated systems.

12. Introducing Demand Shifting

    Since majority of renewable energy is curtailed during Sundays, it is necessary to formulate a mechanism to shift certain weekday demands to Sundays. This can be done at minimum cost by introducing necessary tariff structures to promote industries and commercial establishments to operate in Sundays and reduce the demand on weekdays. A rotational mechanism for each consumer could be proposed for selection of the weekday for demand shifting, such that demand reduction is evenly distributed within all weekdays.

    Further, introducing a Time of Use (TOU) cost reflective tariff shall also encourage the customers to shift their night loads to the daytime, thus, reducing curtailments during daytime and preventing high cost generation during the night peak.

    The necessary background studies for these demand shifting strategies need to be conducted and such need to be introduced by year 2026 to mitigate excess renewable energy curtailments.

13. Introducing Demand response schemes and flexible loads

    Introducing demand response methods and conducting studies for finding load management strategies and investigating the possibility of introducing flexible loads such as electric vehicles, desalination plants, hydrogen production, ammonia production, etc., in view of altering the demand profiles as required for maximum utilization of renewable energy and for ensuring system stability.

14. Cross border electricity trade

    The proposed project is an asynchronous interconnection between the Indian and Sri Lankan electricity grids through a 2 x 500 MW HVDC link from Madurai New (India) to Mannar (Sri Lanka) with 500 MW as phsse-1. The interconnection would also promote regional cooperation, reduce reliance on fossil fuels while supporting the integration of renewable energy, contributing to the region's sustainability goals.

    However, the 500 MW interconnection is proposed by the year 2039 which is beyond the initial ten years of the planning horizon. Hence as preliminary steps it is essential to initiate agreements on understanding between the two countries, and select optimum business model to construct the interconnection. Possibilities of cost reduction should be evaluated prior to commitment of such large scale infrastructure project.

15. Nuclear Power Development

    Nuclear power is a main source of low-carbon electricity globally and is widely regarded as a key technology with significant potential to combat climate change. By 2044, a 600 MW nuclear power capacity is projected, making it a viable option for base load operation, especially after the retirement of coal power plants. As coal plants phase out, nuclear energy is expected to become a more cost-effective and reliable alternative for sustaining base load power, ensuring a stable and continuous energy supply while contributing to the reduction of carbon emissions.

    Integrating a conventional nuclear plant into the system poses significant challenges, particularly due to its complexity and the stringent legal and infrastructure requirements involved. As this project is identified beyond a 15-year planning horizon, it is crucial to initiate preliminary work related to legal frameworks and infrastructure development. Rasing stakeholder awareness and social acceptance shall be critical for undertaking a nuclear power development program in Sri Lanka,

    Accommodating a nuclear power unit above 600 MW within Sri Lanka's network will be technically challenging, especially considering the anticipated demand growth and a generation mix increasingly dominated by variable renewable energy sources. Ensuring that the grid can handle the integration of such a large and stable power source, amidst a dynamic and variable energy environment, will require careful planning, advanced technology, and robust grid management strategies. Further, Small Modular Reactors (SMR) are globally still under research level and those can become a proven technology in future. Hence, during detailed studies, possible options with lower unit capacity sizes are preferred to be pursued.

16. Exploring the possibilities of Green Hydrogen Production, Storage and Usage

    Since majority of renewable energy is curtailed with seasonal patterns, new storage solutions other than conventional storage solutions have to be considered beyond year 2030. Green Hydrogen production is emerging as a promising technology, which requires detailed feasibility studies to be conducted on its production patterns, storage mechanisms and potential applications to Sri Lanka including power generation, transportation, industrial applications and production of fertilizer.

17. Power Purchase Agreement for Biomass with Seasonal tariff adjustment

The development of biomass power plants as expected in the Base case scenario shall pay a major role in achieving the envisioned renewable energy targets. However, since the limited availability of biomass resource can be observed, it is beneficial to utilize the resource, during the periods its most essential. It is proposed to introduce a seasonal tariff adjustment for biomass resource such that, the maximum generation is encouraged during dry season and limited generation can be expected during high wind season, to minimize curtailment of VRE generation.

18. Conducting System Strengthening Studies

Conducting studies for necessary grid interventions such as introducing synchronous condensers for maintaining inertia of the network with high non-synchronous penetration, introducing reactive power compensators, etc.

Conducting further studies to investigate the necessity of system non-synchronous penetration (SNSP) limits considering targeted years to achieve smooth operation of the power system. Such studies need to be periodically reviewed with the actual progression of the power system SNSP limits.

CHAPTER 15
REVISIONS TO PREVIOUS PLAN

15.1 Background

This chapter examines the deviations of the results of the present study (LTGEP 2025-2044) from that of the previous generation expansion plan (LTGEP 2023-2042) and analyses the factors for such deviations.

This chapter focuses on the main differences from the previous plan under following areas.

1. Government Policies
2. Base Demand Forecast
3. Fuel Prices
4. Capacity integration of Other Renewable Energy (ORE)
5. Integration of Storage Systems
6. Capacity share and Energy share
7. Environmental Emissions

15.2 Government Policies

"General Policy Guidelines on the Electricity Industry 2021" issued in January 2022 is the guideline used in preparation of both LTGEP 2025-2044 and LTGEP 2023-2042, since no new policy was issued after 2022.

The policy aims to achieve 70% of electricity generation by 2030 from renewable sources and carbon neutrality in power generation by 2050.

15.3 Base Demand Forecast

As depicted in the demand forecast study carried out for LTGEP 2025-2044, the night peak, day peak and off peak shows an increasing trend but in particular, the growth of the day peak was higher than the growth of night peak. It is estimated that the day peak would surpass night peak in 2025. The shape of the daily load profile also undergoes gradual changes.

Base Demand Forecast of LTGEP is a combination of time series modelling and econometric approach as described in Chapter 3. Twenty five year average growth rates of Energy demand and Peak demand forecasts of LTGEP 2025-2044 are respectively 4.8% and 4.9% while it is 5% and 4.9% in LTGEP 2023-2042. Figure 15.1 & 15.2 shows the Energy demand and Peak forecast comparison of two LTGEPs.

As illustrated in Figure 15.1 & 15.2, both the annual energy demand and annual peak demand of LTGEP 2025-2044 are moderately lower than the LTGEP 2023-2044 in initial years, and this difference widens along the horizon. This is mainly due to the demand lag observed during initial years created with the economic crisis in the country.

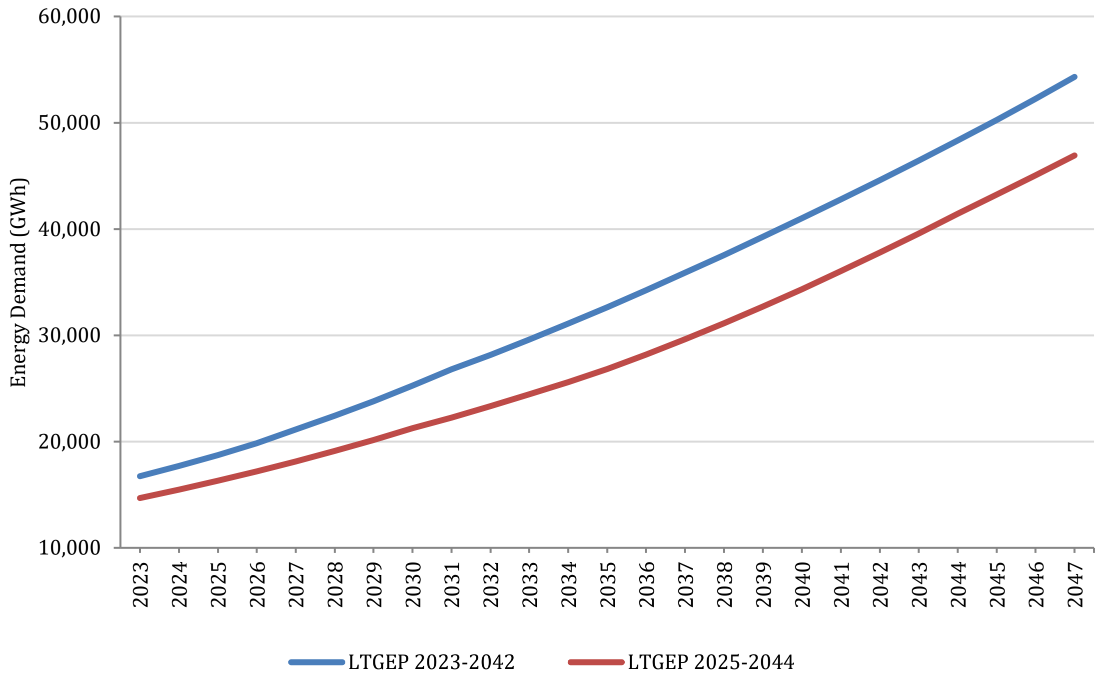


Figure 15.1 - Comparison of Energy Demand Forecasts used in LTGEP 2025-2044 and LTGEP 2023-2042

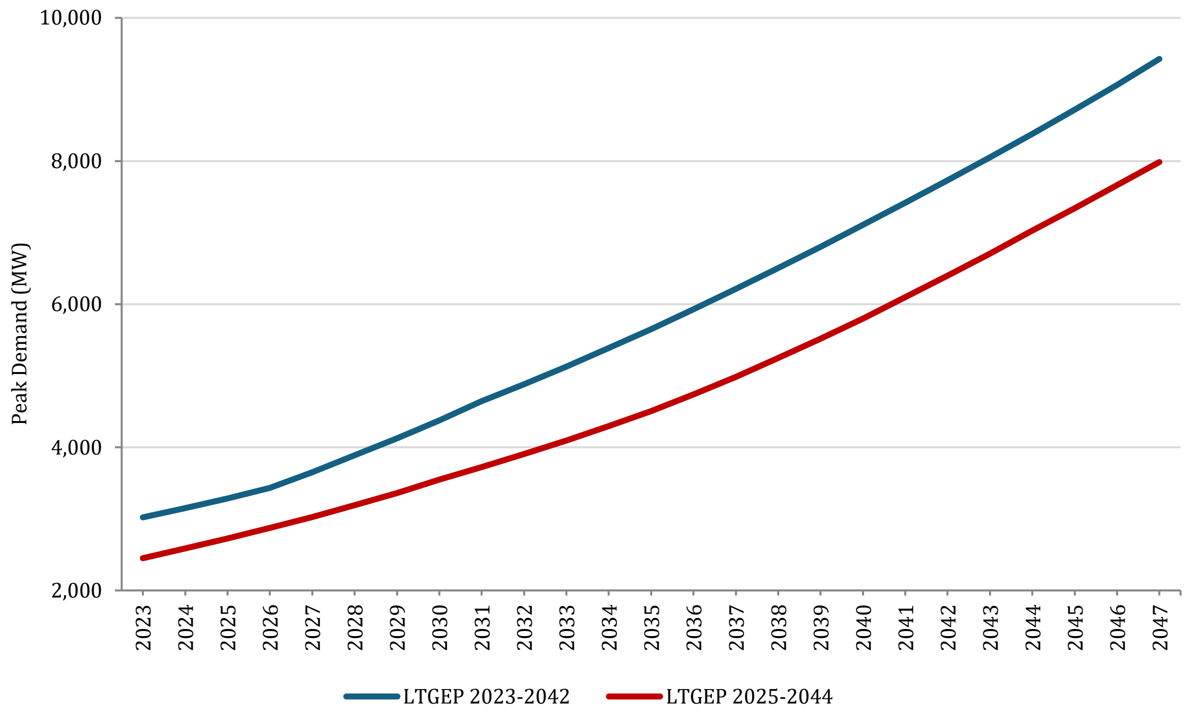


Figure 15.2 - Comparison of Peak Demand Forecasts used in LTGEP 2025-2044 and LTGEP 2023-2042

15.4 Fuel Prices used for Planning Studies

A fixed fuel price is considered throughout the planning horizon. Fuel Prices of Coal, Natural Gas and Oil for the present study (LTGEP 2025-2044) were based on future projections by World Bank in "World Bank Commodity Price Forecasts – October 2023". All fuel prices are considered in economic terms (as the price delivered at the power plant exclusive of tax). A comparison of fuel prices used in the LTGEP 2023-2042 and LTGEP 2025-2044 are shown in Figure 15.3.

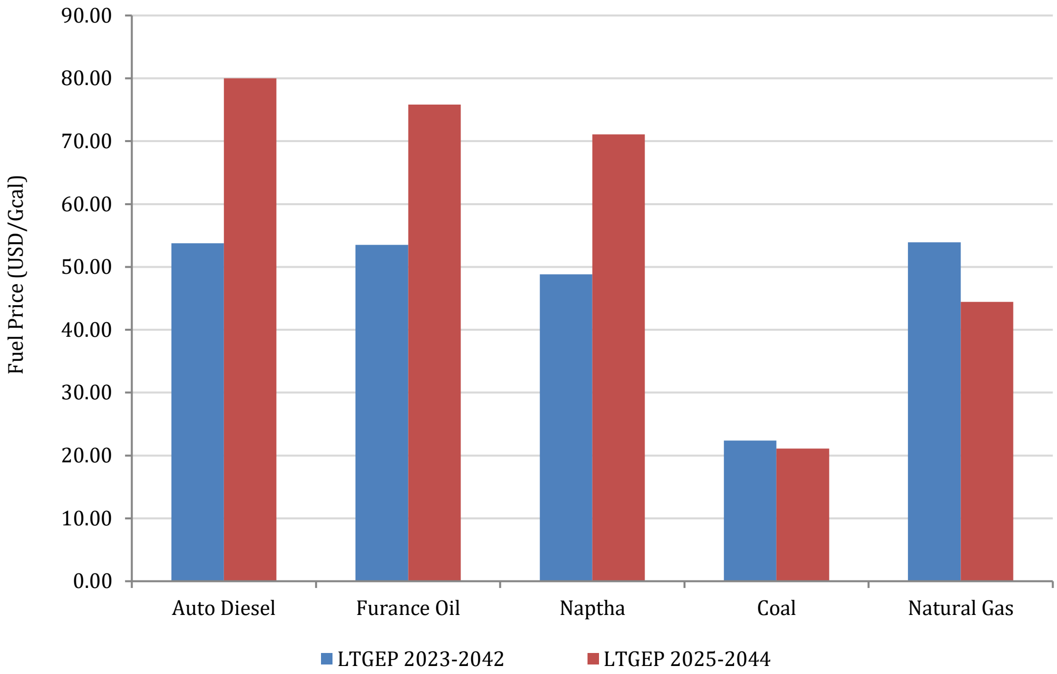


Figure 15.3 - Comparison of Fuel Prices used in LTGEP 2025-2044 and LTGEP 2023-2042

15.5 Integration of Other Renewable Energy Sources

Figure 15.4 shows a comparison of Other Renewable Energy (ORE) capacity contribution in the years of 2025, 2030, 2035 and 2040 with respect to LTGEP 2023-2042 and the LTGEP 2025-2044 by different sources. In 2042, the total ORE capacity decreased by 4,245 MW, which is 27% lower than the capacity projected in the LTGEP 2023-2042. This is mainly due to the decrease in electricity demand projection.

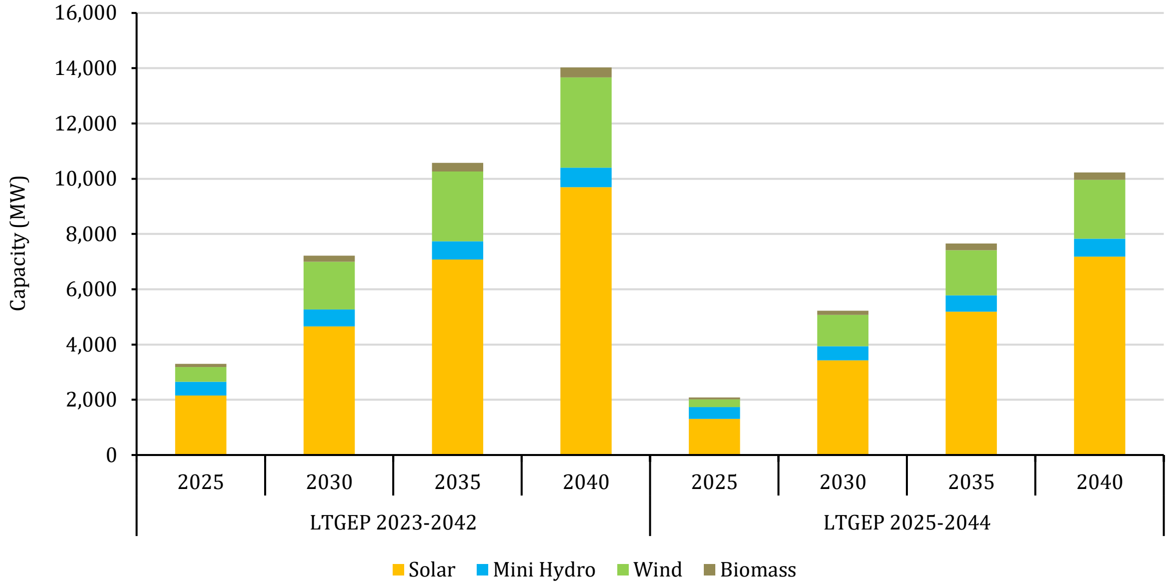


Figure 15.4 - Comparison of ORE Capacities in LTGEP 2025-2044 and LTGEP 2023-2042

15.6 Integration of Storage Systems

Figure 15.5 presents a comparison of Battery Energy Storage and Pump Hydro Storage additions in LTGEP 2023-2042 and the LTGEP 2025-2044. Compared to LTGEP 2023-2042, significant reduction of energy storage additions can be observed. This decrease is primarily associated with the reduction in demand and resultant ORE additions. The integration of the pumped storage power plant has been deferred in the optimization, due to the recent reduction in projected demand as well as allowing sufficient time to complete the activities associated with the project. The increase in system non-synchronous penetration up to 75% also allows an opportunity to achieve policy targets without investing in high duration storage. Capacities beyond 2030 are to be re-evaluated in future planning cycles based on the progress of the renewable energy development and other grid interventions.

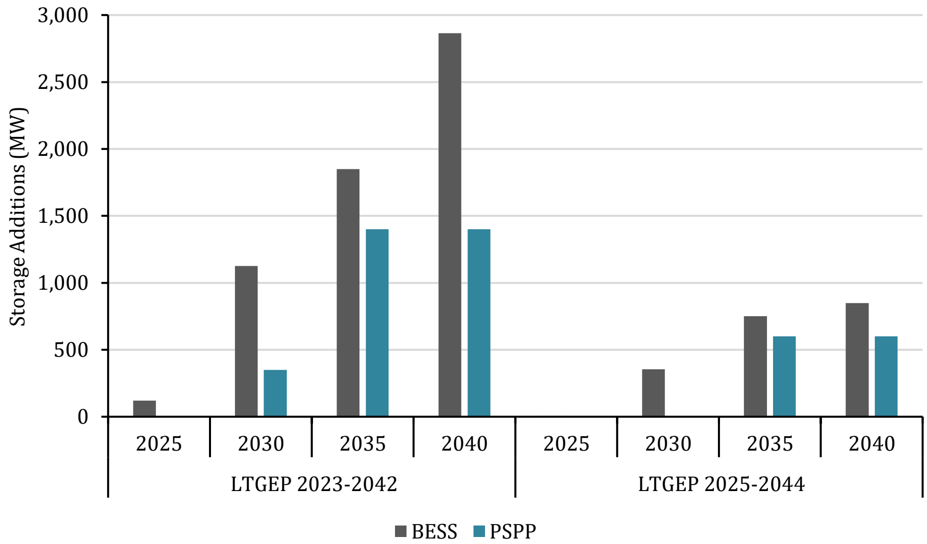


Figure 15.5 - Comparison of Storage Additions in LTGEP 2025-2044 and LTGEP 2023-2042

15.7 Integration of HVDC Interconnection

Implementation of 500 MW HVDC interconnection has been identified in LTGEP 2025-2044 during the year 2039 to support the renewable energy integration. In LTGEP 2023-2042, HVDC interconnection was only considered in an additional scenario, with a proposed implementation timeline of 2034. However, due to a significant increase in the overall project cost and a notable reduction in projected demand, the requirement for the interconnection has been deferred in the LTGEP 2025-20244 compared to LTGEP 2023-2042.

15.8 Capacity Share and Energy Share

In LTGEP 2025-2044, the share of oil based power plants shows a significant increase compared to LTGEP 2023-2042 in year 2025. This is mainly due to the delay in planned LNG infrastructure in the country. In 2030 and 2035, capacity share of ORE based power plants almost remain same while share of Battery Storage has reduced by 4.9% and 4.5% respectively compared to LTGEP 2023-2042. The share of major hydro, coal and natural gas based power plants has increased in LTGEP 2025-2044 compared to LTGEP 2023-2042. Another major difference between two LTGEPs is the introduction of hydrogen blending in natural gas after 2035 in LTGEP 2025-2044. The development of the Interconnection connecting regional grids is introduced in year 2039 of LTGEP 2025-2044. A comparison of capacity shares between LTGEP 2025-2044 and LTGEP 2023-2042 is illustrated in Figure 15.6

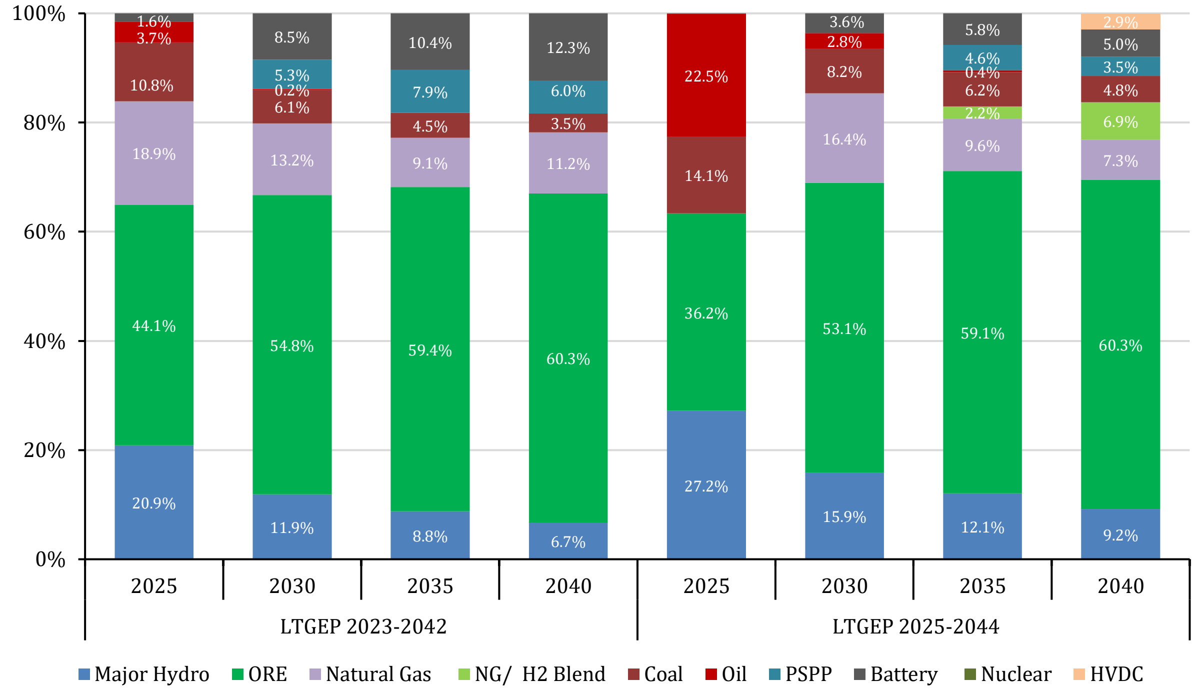


Figure 15.6 - Capacity Share Comparison between LTGEP 2025-2044 and LTGEP 2023-2042

Correspondingly in LTGEP 2025-2044, the energy share of other renewable energy based power plants in year 2030 and 2035 remain almost constant. The main difference in energy share is the presence of oil based energy in LTGEP 2025-2044 due to the absence of natural gas in the fuel mix compared to LTGEP 2023-2042. The energy share of major hydro and coal has increased in LTGEP 2025-2044 compared to LTGEP 2023-2042. The energy share from natural gas based power plants shows a slight decrease while oil based power plants almost cease their generation by 2030. A comparison of energy shares between LTGEP 2025-2044 and LTGEP 2023-2042 is illustrated in Figure 15.7.

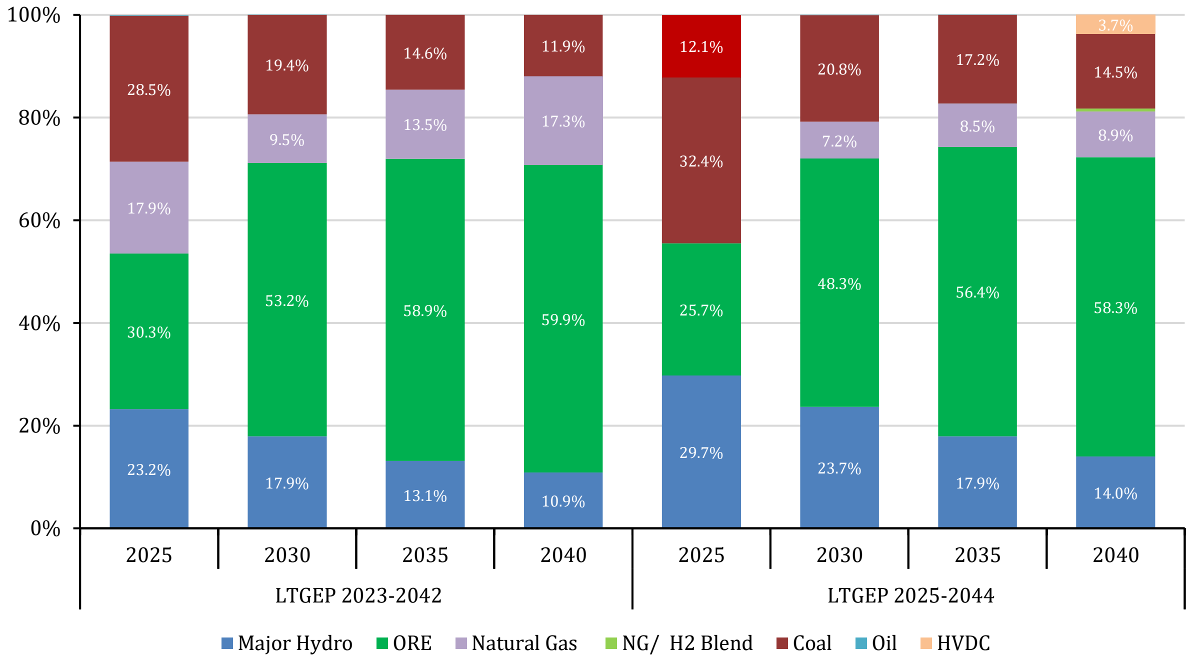


Figure 15.7 - Energy Share Comparison between LTGEP 2025-2044 and LTGEP 2023-2042

15.9 Environmental Emissions

CO_2 and particulate matter (PM) emissions are lower in LTGEP 2025-2044 than the emission level in the LTGEP 2023-2042. SO_2 emissions have increased in the initial years and after 2028 this has drastically reduced due to the introduction of natural gas. The higher amount of NO_x emissions has reduced with the retirement of oil power plants but shows an increasing trend after 2035 due to the introduction of hydrogen blended natural gas power plants. However, NOx emissions has significantly reduced in 2044 after retirement of coal power plants. Comparison of these environmental emissions are shown in Figure 15.8 and Figure 15.9.

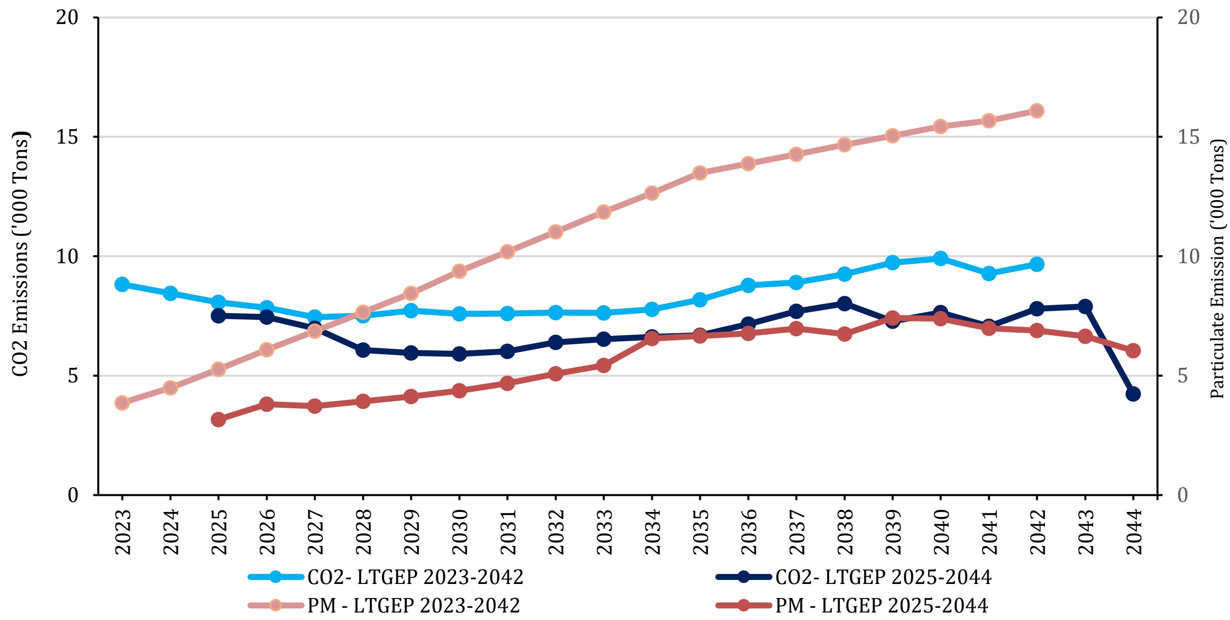


Figure 15.8 - CO_2 and PM Emissions Comparison between LTGEP 2025-2044 and LTGEP 2023-2042

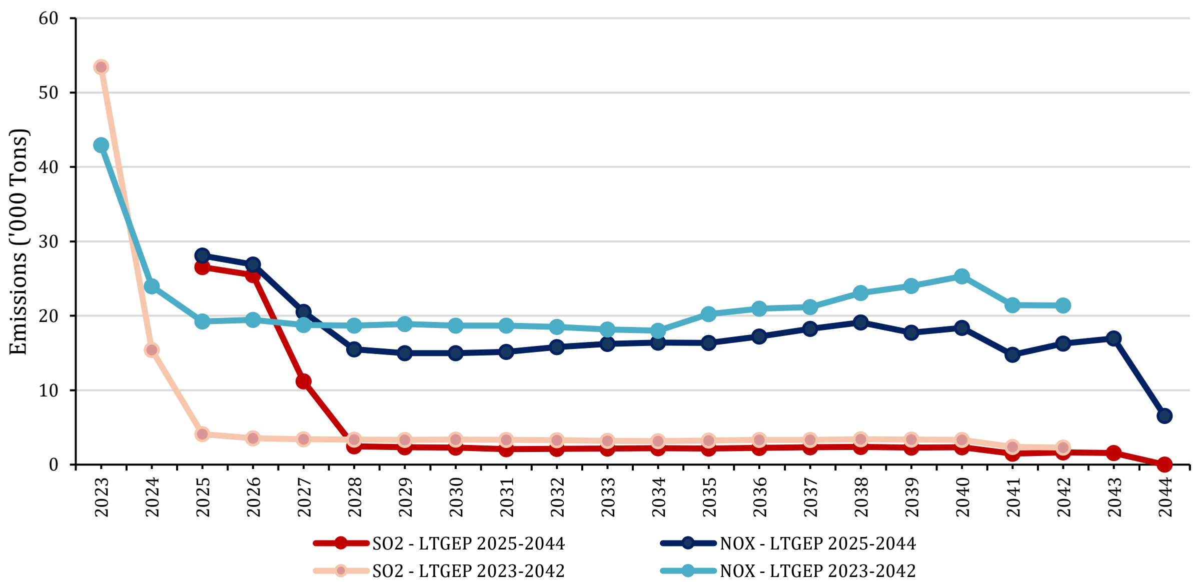


Figure 15.9 – SO_2 and NO_x Emissions Comparison Between LTGEP 2025-2044 and LTGEP 2023-2042

15.10 Overall Comparison

The overall comparison of thermal generation expansions proposed by plans for last 20 years and actual implementation is shown in Annex 15.1.

The overall comparison of renewable generation expansions proposed by plans for last 8 years and actual implementation is shown in Annex 15.2.

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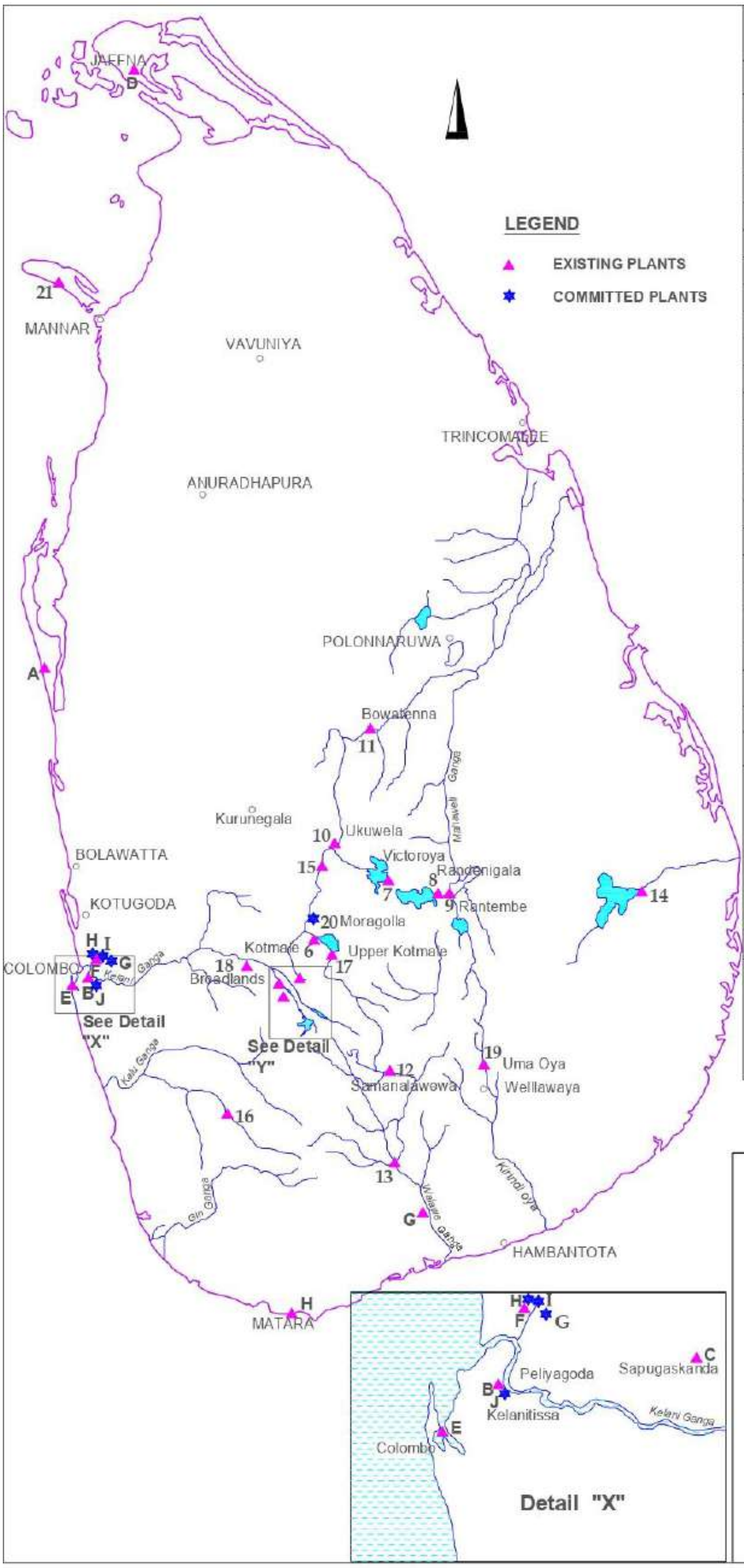
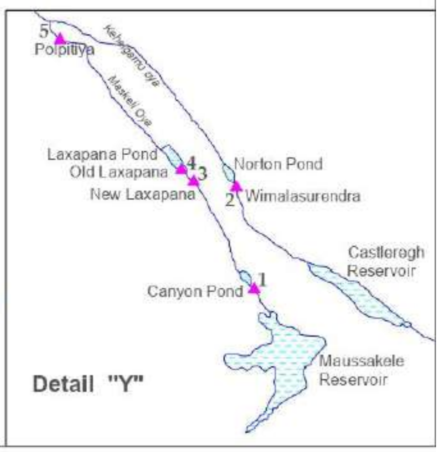
Annex 2.1

Location of Existing, Committed and Candidate Power Stations

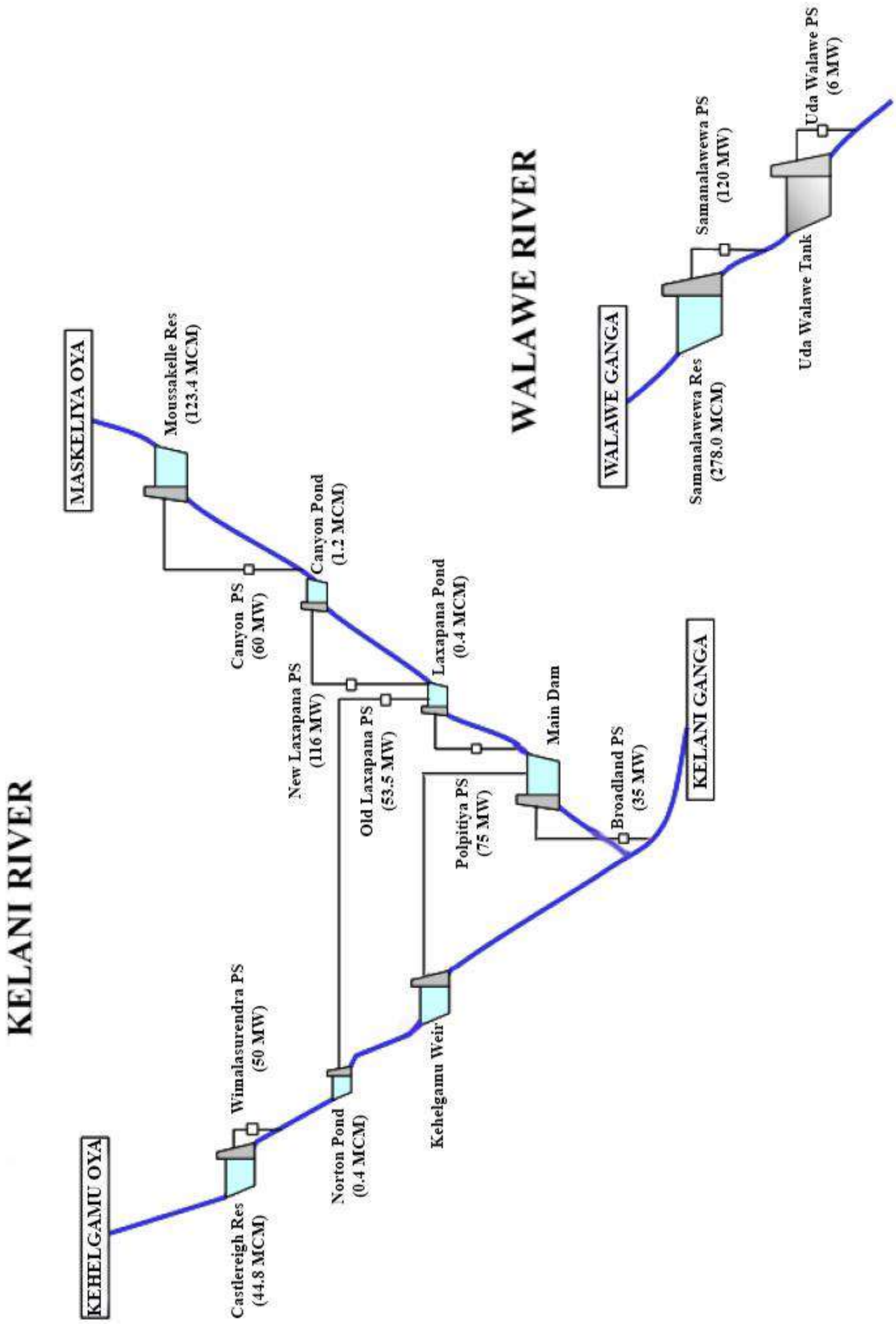




No	POWER PLANT	CAPACITY MW
	Hydro Power Plants (Existing)	
1	Canyon	60
2	Wimalasurendra	50
3	New Laxapana	100
4	Old Laxapana	50
5	Polpitiya	90
6	Kotmale	201
7	Victoriya	210
8	Randenigala	120
9	Rantembe	50
10	Ukuwela	40
11	Bowatenna	40
12	Samanalawewa	120
13	Udawalawe	06
14	Inginiyagala	11
15	Nilambe	03
16	Kukule	75
17	Upper Kotmale	150
18	Broadlands	35
19	Uma Oya	122
	Hydro Power Plants (Committed)	
20	Moragolla	30
	Other Renewable(Existing)	
21	Mannar Wind Park	100
	Thermal Power Plants (Existing)	
A	Lakvijaya Coal Power Plant	900
B	Kelanithissa CCY1, CCY2	165,163
C	Sapugaskanda PP	160
D	Uthuru Janani	27
E	CEB Barge Mounted Plant	62
F	West Coast PP	270
	Thermal Power Plants (Committed)	
G	Sobadhanavi Combine Cycle Plant	350
H	Natural Gas Combine Cycle Plant Kelawarapitiya - ii	350
I	IC Engine	200
J	Kelanithissa GT	130

Annex 2.2

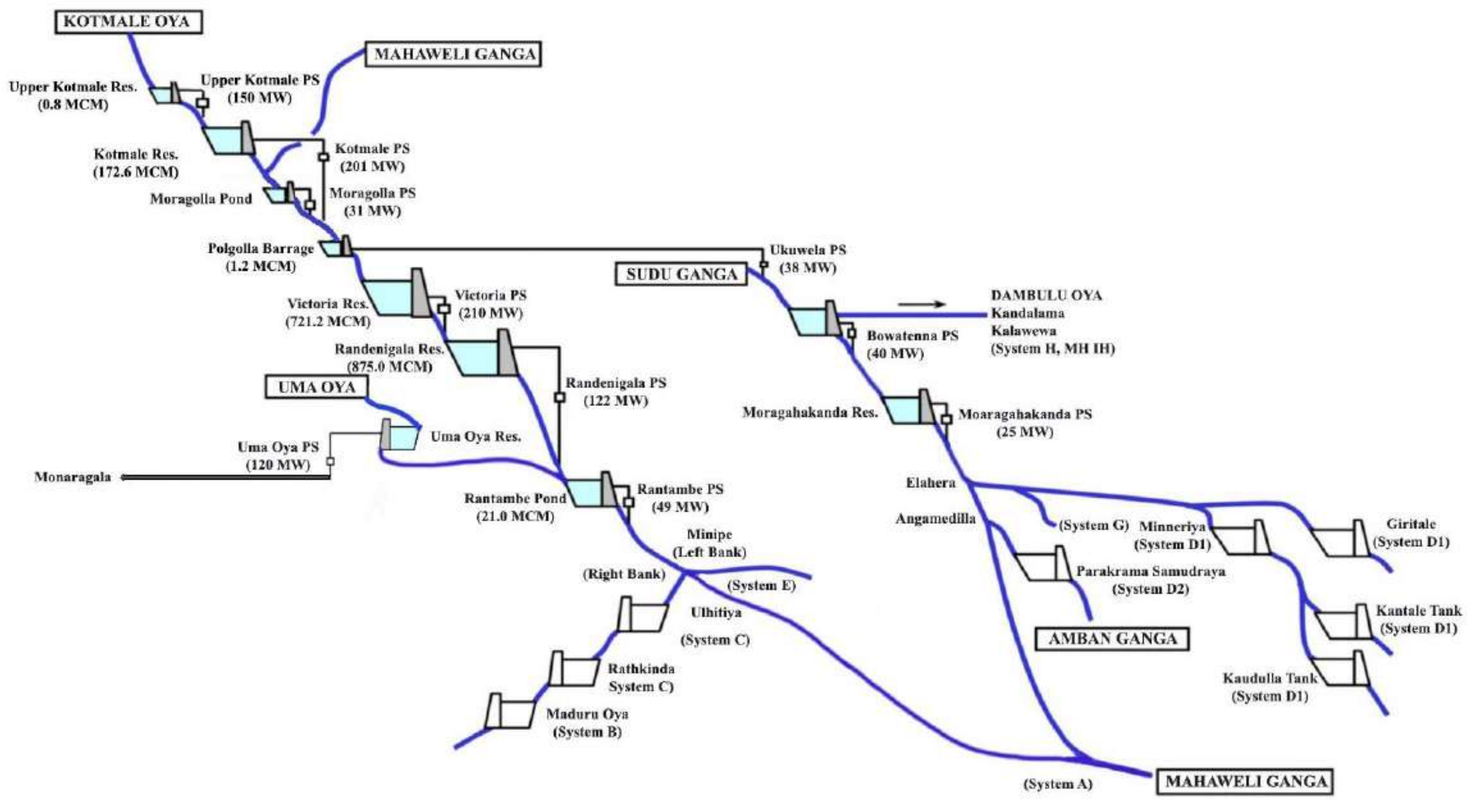
Reservoir Systems in Mahaweli, Kelani and Walawe River Basins



A2.1.1 Reservoir Systems in Kelani and Walawe River Basins

A2.1.2 Reservoir System in Mahaweli River Basin

MAHAWELI RIVER



Annex 3.1

Scenarios and Sensitivities of the Demand Forecast

Table A3.1 – High Demand Forecast

Year	Demand[1] (GWh)	Net Losses[2](%)	Generation (GWh)	Day Peak (MW)
2025	16,483	7.93	17,902	2,754
2026	17,463	7.76	18,931	2,916
2027	18,501	7.62	20,026	3,088
2028	19,601	7.48	21,184	3,270
2029	20,766	7.34	22,411	3,464
2030	22,000	7.34	23,742	3,674
2031	23,676	7.33	25,549	3,958
2032	24,794	7.33	26,755	4,149
2033	25,984	7.32	28,038	4,353
2034	27,269	7.32	29,422	4,574
2035	28,636	7.31	30,896	4,808
2036	30,105	7.31	32,479	5,061
2037	31,672	7.31	34,168	5,330
2038	33,346	7.30	35,972	5,618
2039	35,103	7.30	37,866	5,921
2040	36,956	7.29	39,863	6,240
2041	38,916	7.29	41,974	6,578
2042	40,910	7.28	44,123	6,923
2043	42,966	7.28	46,338	7,279
2044	45,101	7.27	48,638	7,650
2045	47,149	7.27	50,845	8,006
2046	49,226	7.26	53,082	8,368
2047	51,351	7.26	55,370	8,739
2048	53,428	7.25	57,607	9,103
2049	55,495	7.25	59,833	9,466
5 Year Average Growth	5.9%		5.8%	5.9%
10 Year Average Growth	5.8%		5.7%	5.8%
20 Year Average Growth	5.4%		5.4%	5.5%
25 Year Average Growth	5.2%		5.2%	5.3%

[1]In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

[2] Net losses include losses at the Transmission & Distribution levels. Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

Table A3.2 – Low Demand Forecast

Year	Demand[1] (GWh)	Net Losses[2](%)	Generation (GWh)	Day Peak (MW)
2025	16,263	7.93	17,664	2,717
2026	17,114	7.76	18,553	2,858
2027	18,010	7.62	19,495	3,006
2028	18,953	7.48	20,485	3,162
2029	19,946	7.34	21,526	3,327
2030	20,990	7.34	22,652	3,505
2031	21,936	7.33	23,672	3,667
2032	22,918	7.33	24,731	3,836
2033	23,936	7.32	25,827	4,010
2034	24,997	7.32	26,971	4,193
2035	26,123	7.31	28,185	4,386
2036	27,342	7.31	29,498	4,596
2037	28,633	7.31	30,889	4,819
2038	30,000	7.30	32,362	5,054
2039	31,391	7.30	33,862	5,295
2040	32,843	7.29	35,426	5,546
2041	34,361	7.29	37,062	5,809
2042	35,887	7.28	38,706	6,073
2043	37,442	7.28	40,381	6,344
2044	39,038	7.27	42,100	6,621
2045	40,594	7.27	43,776	6,893
2046	42,152	7.26	45,454	7,166
2047	43,728	7.26	47,151	7,442
2048	45,249	7.25	48,788	7,710
2049	46,810	7.25	50,469	7,984
5 Year Average Growth	5.2%		5.1%	5.2%
10 Year Average Growth	4.9%		4.8%	4.9%
20 Year Average Growth	4.7%		4.7%	4.8%
25 Year Average Growth	4.5%		4.5%	4.6%

[1]In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.
[2] Net losses include losses at the Transmission & Distribution levels. Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

Table A3.3- Long Term Time Trend Demand Forecast

Year	Demand[1] (GWh)	Net Losses[2] (%)	Generation (GWh)	Day Peak (MW)
2025	19,744	7.93	21,444	3,299
2026	20,787	7.76	22,535	3,471
2027	21,885	7.62	23,689	3,653
2028	23,041	7.48	24,903	3,844
2029	24,259	7.34	26,181	4,046
2030	25,540	7.34	27,563	4,265
2031	26,890	7.33	29,017	4,495
2032	28,310	7.33	30,549	4,738
2033	29,806	7.32	32,161	4,994
2034	31,381	7.32	33,859	5,263
2035	33,038	7.31	35,646	5,548
2036	34,784	7.31	37,527	5,847
2037	36,622	7.31	39,508	6,163
2038	38,556	7.30	41,593	6,496
2039	40,593	7.30	43,788	6,847
2040	42,738	7.29	46,099	7,216
2041	44,996	7.29	48,532	7,606
2042	47,373	7.28	51,094	8,017
2043	49,876	7.28	53,791	8,450
2044	52,511	7.27	56,630	8,907
2045	55,285	7.27	59,619	9,388
2046	58,206	7.26	62,765	9,895
2047	61,281	7.26	66,078	10,429
2048	64,519	7.25	69,566	10,993
2049	67,928	7.25	73,237	11,587
5 Year Average Growth	5.3%		5.1%	5.2%
10 Year Average Growth	5.3%		5.2%	5.3%
20 Year Average Growth	5.3%		5.2%	5.4%
25 Year Average Growth	5.3%		5.3%	5.4%

[1]In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

[2] Net losses include losses at the Transmission & Distribution levels. Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

Table A3.4 –Aggressive EV Projection

Year	Demand[1] (GWh)	Net Losses[2](%)	Generation (GWh)	Day Peak (MW)
2025	16,351	7.93	17,759	2,730
2026	17,260	7.76	18,711	2,881
2027	18,236	7.62	19,739	3,046
2028	19,296	7.48	20,855	3,227
2029	20,471	7.34	22,093	3,428
2030	21,809	7.34	23,536	3,666
2031	22,962	7.33	24,779	3,869
2032	24,193	7.33	26,107	4,086
2033	25,508	7.32	27,524	4,319
2034	26,928	7.32	29,054	4,573
2035	28,483	7.31	30,731	4,852
2036	30,219	7.31	32,602	5,165
2037	32,134	7.31	34,666	5,513
2038	34,254	7.30	36,952	5,901
2039	36,555	7.30	39,432	6,325
2040	39,088	7.29	42,162	6,796
2041	41,295	7.29	44,541	7,196
2042	43,572	7.28	46,995	7,610
2043	45,948	7.28	49,555	8,044
2044	48,442	7.27	52,242	8,500
2045	50,974	7.27	54,969	9,010
2046	53,594	7.26	57,792	9,551
2047	56,327	7.26	60,736	10,124
2048	59,102	7.25	63,725	10,732
2049	62,025	7.25	66,873	11,376
5 Year Average Growth	5.8%		5.6%	5.9%
10 Year Average Growth	5.7%		5.6%	5.9%
20 Year Average Growth	5.9%		5.8%	6.2%
25 Year Average Growth	5.7%		5.7%	6.1%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

1 Net losses include losses at the Transmission & Distribution levels, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the renewable thermal generation mix of the future.

Annex 4.1

Specific Cost Curves of Thermal Generation Options

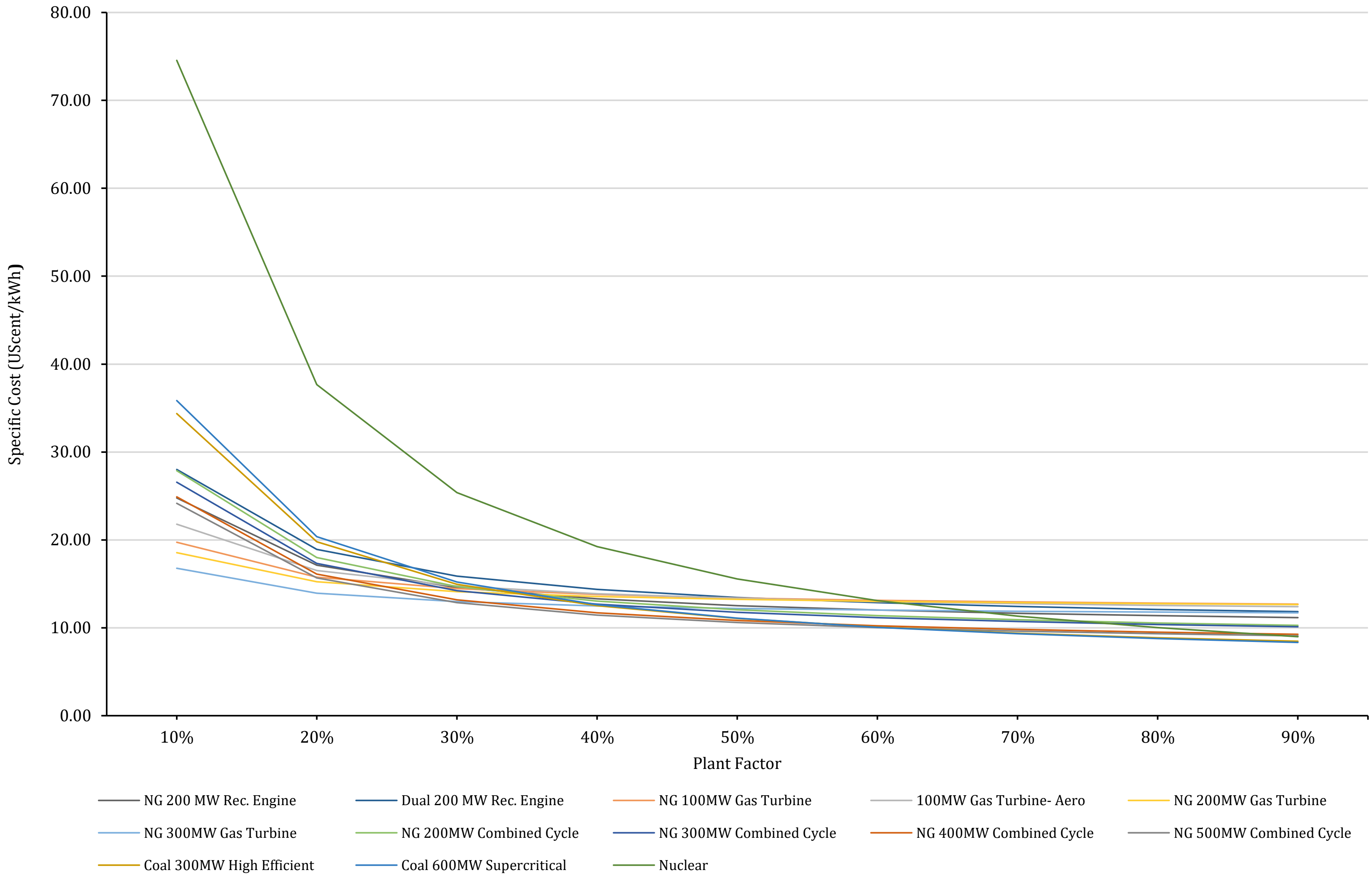
The specific cost and corresponding curves for the candidate thermal generation options are mentioned below.

A4.1 Specific Cost of Candidate Thermal Plants in US cents/kWh (in LKR/kWh)

Power Plant	Plant Factor								
	0.10	**0.20**	**0.30**	**0.40**	**0.50**	**0.60**	**0.70**	**0.80**	**0.90**
50 MW NG IC Engine	26.45	17.95	15.12	13.70	12.85	12.29	11.88	11.58	11.34
	(86.41)	(58.65)	(49.40)	(44.77	(42.00)	(40.15)	(38.83)	(37.84)	(37.06)
50 MW FO IC Engine	35.97	26.21	22.95	21.33	20.35	19.70	19.23	18.89	18.61
	(117.53)	(85.63)	(75.00)	(69.68	(66.49)	(64.37)	(62.85)	(61.71)	(60.82)
50 MW DUAL IC Engine	29.67	19.74	16.43	14.78	13.78	13.12	12.65	12.29	12.02
	(96.94)	(64.50)	(53.68)	(48.28	(45.03)	(42.87)	(41.33)	(40.17)	(39.27)
100 MW NG IC Engine	25.60	17.53	14.84	13.49	12.68	12.15	11.76	11.47	11.25
	(83.65)	(57.27)	(48.48)	(44.08	(41.45)	(39.69)	(38.43)	(37.49)	(36.76)
100 MW FO IC Engine	35.14	25.79	22.68	21.12	20.18	19.56	19.12	18.78	18.52
	(114.81)	(84.27)	(74.09)	(69.00	(65.95)	(63.91)	(62.46)	(61.37)	(60.52)
100 MW DUAL IC Engine	28.84	19.32	16.15	14.57	13.62	12.98	12.53	12.19	11.93
	(94.23)	(63.14)	(52.78)	(47.60	(44.49)	(42.42)	(40.94)	(39.83)	(38.96)
200 MW NG IC Engine	24.77	17.11	14.56	13.28	12.52	12.01	11.64	11.37	11.16
	(80.93)	(55.91)	(47.57)	(43.40)	(40.90)	(39.24)	(38.04)	(37.15)	(36.46)
200 MW FO IC Engine	34.31	25.38	22.40	20.91	20.02	19.42	19.00	18.68	18.43
	(112.09)	(82.91)	(73.19)	(68.32)	(65.41)	(63.46)	(62.07)	(61.03)	(60.22)
200 MW DUAL IC Engine	28.01	18.91	15.88	(14.36	13.46	12.85	12.42	12.09	11.84
	(91.53)	(61.80)	(51.89)	(46.94)	(43.96)	(41.98)	(40.57)	(39.50)	(38.68)
50 MW NG Gas Turbine	23.86	18.67	16.94	16.07	15.55	15.20	14.96	14.77	14.63
	(77.95)	(60.99)	(55.33)	(52.51)	(50.81)	(49.68)	(48.87)	(48.27)	(47.79)
50 MW NG Gas Turbine (Aero)	24.46	17.77	15.54	14.43	13.76	13.31	12.99	12.75	12.57
	(79.94)	(58.07)	(50.78)	(47.14)	(44.95)	(43.49)	(42.45)	(41.67)	(41.06)
100 MW NG Gas Turbine	19.73	15.77	14.45	13.79	13.40	13.13	12.94	12.80	12.69
	(64.47)	(51.53)	(47.22)	(45.07)	(43.77)	(42.91)	(42.30)	(41.83)	(41.47)
100 MW NG Gas Turbine (Aero)	21.78	16.51	14.75	13.87	13.34	12.99	12.74	12.55	12.40
	(71.18)	(53.93)	(48.19)	(45.31)	(43.59)	(42.44)	(41.62)	(41.00)	(40.52)
200 MW NG Gas Turbine	18.55	15.23	14.12	13.56	13.23	13.01	12.85	12.73	12.64
	(60.60)	(49.75)	(46.13)	(44.32)	(43.24)	(42.51)	(42.00)	(41.61)	(41.31)
300 MW NG Gas Turbine	16.77	13.92	12.97	12.49	12.21	12.02	11.88	11.78	11.70
	(54.80)	(45.48)	(42.38)	(40.82)	(39.89)	(39.27)	(38.83)	(38.49)	(38.24)
200 MW NG Combined Cycle	27.87	17.98	14.68	13.03	12.04	11.38	10.91	10.55	10.28
	(91.08)	(58.74)	(47.96)	(42.56)	(39.33)	(37.17)	(35.63)	(34.48)	(33.58)
300 MW NG Combined Cycle	26.56	17.31	14.23	12.69	11.76	11.14	10.70	10.37	10.12
	(86.79)	(56.56)	(46.49)	(41.45)	(38.43)	(36.41)	(34.97)	(33.89)	(33.05)
400 MW NG Combined Cycle	24.90	16.10	13.17	11.70	10.82	10.24	9.82	9.50	9.26
	(81.35)	(52.61)	(43.03)	(38.24)	(35.36)	(33.44)	(32.08)	(31.05)	(30.25)

Power Plant	Plant Factor								
	0.10	**0.20**	**0.30**	**0.40**	**0.50**	**0.60**	**0.70**	**0.80**	**0.90**
500 MW NG Combined Cycle	24.16	15.68	12.85	11.44	10.59	10.03	9.62	9.32	9.08
	(78.95)	(51.23)	(41.99)	(37.38)	(34.60)	(32.76)	(31.44)	(30.45)	(29.68)
300 MW High Efficient Coal Plant	34.37	19.80	14.94	12.51	11.06	10.09	9.39	8.87	8.47
	(112.29)	(64.69)	(48.82)	(40.89)	(36.13)	(32.96)	(30.69)	(28.99)	(27.67)
600 MW Super Critical Coal Plant	35.85	20.37	15.21	12.63	11.09	10.05	9.32	8.76	8.33
	(117.13)	(66.56)	(49.71)	(41.28)	(36.22)	(32.85)	(30.44)	(28.63)	(27.23)
600 MW Nuclear Power Plant	74.55	37.67	25.38	19.23	15.54	13.08	11.33	10.01	8.99
	(243.59)	(123.09)	(82.92)	(62.83)	(50.78)	(42.75)	(37.01)	(32.71)	(29.37)

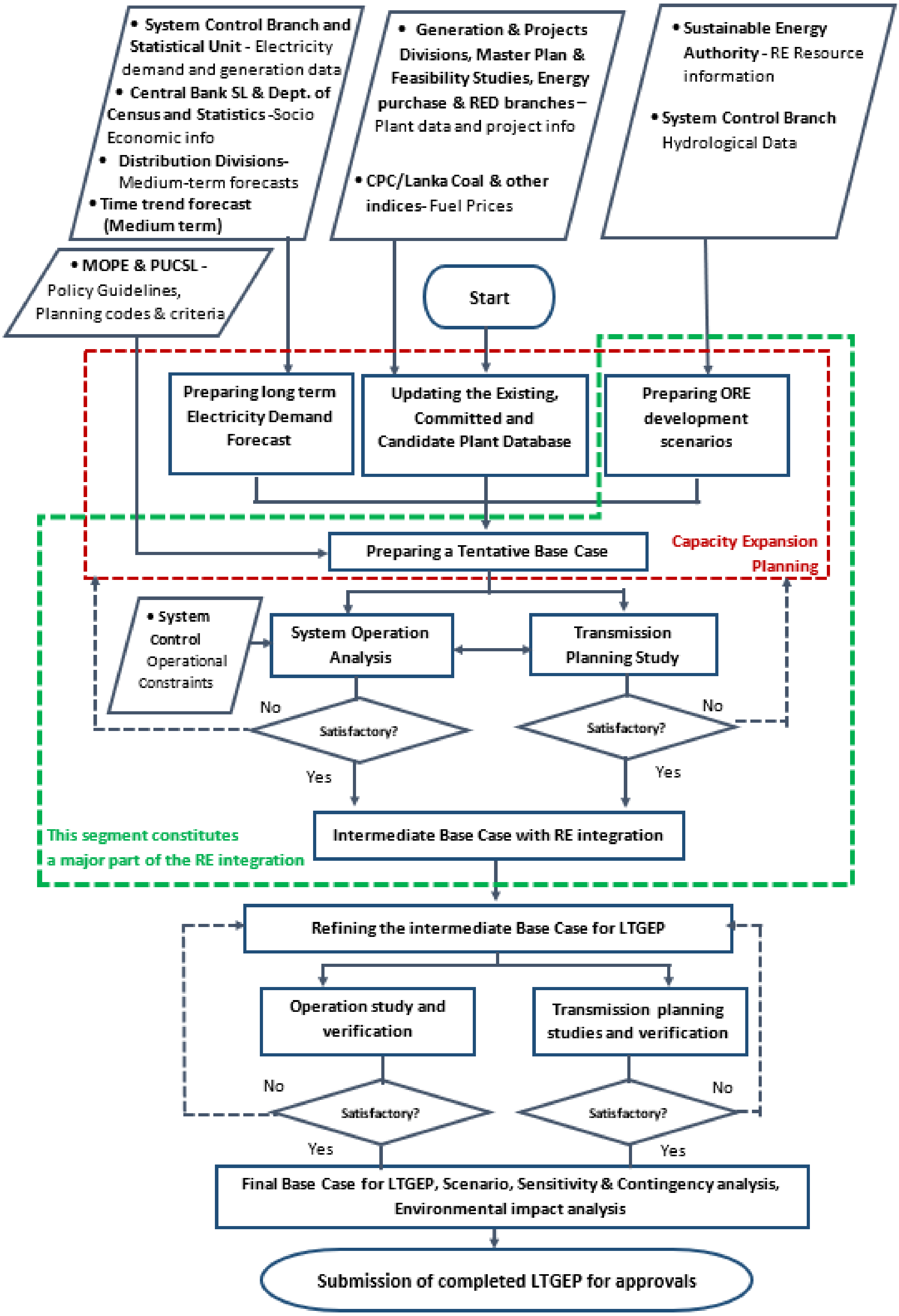
A4.2 Specific Cost Curves of the candidate Options at 10% discount rate



Annex 7.1

Generation Expansion Planning Methodology

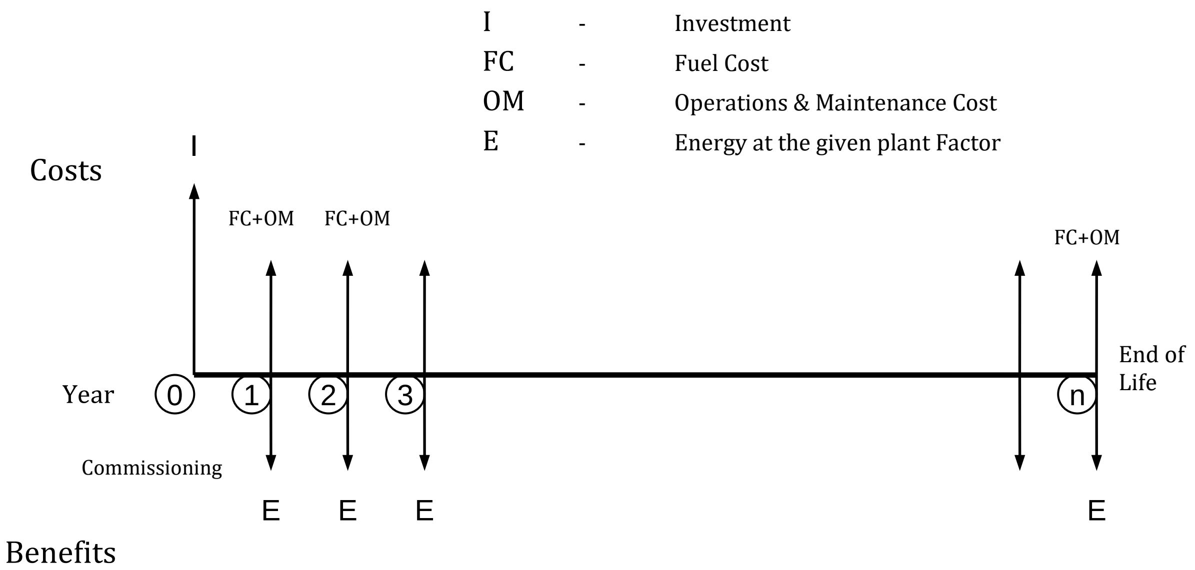
Flow diagram of the generation expansion planning methodology is shown below.



Annex 7.2

Methodology of the Specific Cost Calculation

Present value of specific energy cost of thermal plants is calculated for a range of plant factors, in order to mimic the procedure adopted in the planning software's used for the expansion studies.



Investment cost assumed as an overnight cost to occur at the beginning of the commissioning year as presented in above figure. Yearly fixed and variable operation, maintenance and repair costs are discounted to the beginning of the commissioning year while annual fuel costs are also discounted considering the fuel escalation rates. Energy is calculated for each year of operation over the life time for various plant factors.

Specific Cost = [I + { Σ Fixed OM + (FC + Var. OM) * E } * Present Value Factor] / E * Present Value Factor

Annex 8.1
Results of Generation Expansion Planning Studies 2025-2044

Scenario 1: Maintain 70% RE from 2030 onwards, With 500 MW HVDC interconnection, No coal capacity additions

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass Battery Energy Storage	150 MW **50 MW** **10 MW** 10 MW 10 MW 5 MW/10 MWh	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	150 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Southern Region)	150 MW 300 MW 200 MW 20 MW 20 MW 100 MW/ 400MWh	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 300 MW 150 MW 20 MW 20 MW 100 MW/ 400MWh		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	150 MW 300 MW 150 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa**	**130 MW**
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 100 MW/400 MWh	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	100 MW *(68) MW* *(72) MW* *(62) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b) (d)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c) (e) (f)	
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 200 MW/800 MWh		
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	100 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pumped Storage Power Plant (Maha)	150 MW 200 MW 100 MW 20 MW 20 MW 600 MW		
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 100 MW 10 MW 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 100 MW 10 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 250 MW 100 MW 10 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	HVDC Interconnection	500 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 300 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Gas Turbine - Natural Gas & Hydrogen Blend *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	200 MW 300 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b) (d)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c) (e) (f)	
2042	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 300 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	150 MW 300 MW 500 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	150 MW 300 MW 10 MW 50 MW/200 MWh	Gas Turbine - Natural Gas & Hydrogen Blend Combined Cycle - Natural Gas & Hydrogen Blend *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	300 MW 400 MW *(300) MW* *(300) MW*

Annex 8.2
Results of Generation Expansion Planning Studies 2025-2044

Scenario 2: Maintain 70% RE from 2030 onwards, Without HVDC interconnection, No coal capacity additions

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass Battery Energy Storage	150 MW **50 MW** **10 MW** 10 MW 10 MW 5 MW/10 MWh	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	150 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Southern Region)	150 MW 300 MW 200 MW 20 MW 20 MW 100 MW/ 400MWh	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 300 MW 150 MW 20 MW 20 MW 100 MW/ 400MWh		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	150 MW 300 MW 150 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa**	**130 MW**
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 100 MW/400 MWh	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	100 MW *(68) MW* *(72) MW* *(62) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 200 MW/800 MWh		
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	100 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pumped Storage Power Plant (Maha)	150 MW 200 MW 100 MW 20 MW 20 MW 600 MW		
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 100 MW 10 MW 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 100 MW 10 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 250 MW 100 MW 10 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Battery Energy Storage Pumped Storage Power Plant (Wewathenna)	150 MW 250 MW 100 MW 10 MW 50 MW/ 200MWh 350 MW		
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pumped Storage Power Plant (Wewathenna)	150 MW 400 MW 100 MW 10 MW 350 MW		
2041	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 400 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Gas Turbine - Natural Gas & Hydrogen Blend *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	200 MW 300 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2042	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	150 MW 400 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro Battery Energy Storage	150 MW 400 MW 500 MW 10 MW 200 MW/ 800MWh	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	150 MW 350 MW 500 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Gas Turbine - Natural Gas & Hydrogen Blend Combined Cycle - Natural Gas & Hydrogen Blend *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	100 MW 300 MW 400 MW *(300) MW* *(300) MW*

Annex 8.3

Results of Generation Expansion Planning Studies 2025-2044

Scenario 4: Achieve 70% RE by 2030 and increase to 80% by 2044, With 1000 MW HVDC interconnection, No coal capacity additions

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b) (d)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c) (e) (f)	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass Battery Energy Storage	150 MW **50 MW** **10 MW** 10 MW 10 MW 5 MW/10 MWh	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	150 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Southern Region)	150 MW 300 MW 200 MW 20 MW 20 MW 100 MW/ 400MWh	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 300 MW 150 MW 20 MW 20 MW 100 MW/ 400MWh		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	150 MW 300 MW 150 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa**	**130 MW**
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 200 MW 100 MW 20 MW 20 MW 100 MW/400 MWh	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	100 MW *(68) MW* *(72) MW* *(62) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [a] [b] [d]	THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [a] [c] [e] [f]
2032	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage 200 MW/800 MWh	
2033	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Battery Energy Storage 100 MW/ 400MWh	Gas Turbine - Natural Gas 100 MW *Retirements of* *Combined Cycle Power Plant (KPS) (165) MW* *Combined Cycle Power Plant (KPS-2) (163) MW* *Uthuru Janani Power Plant (26.7) MW*
2034	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 20 MW Biomass 20 MW Pumped Storage Power Plant (Maha) 600 MW	
2035	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 200 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend 300 MW *Retirement of* *West Coast Combined Cycle Power Plant (300) MW*
2036	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend 300 MW
2037	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	HVDC Interconnection 500 MW
2038	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW	IC Engine Power Plant – 200 MW Natural Gas & Hydrogen Blend
2039	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 250 MW Wind 100 MW Mini Hydro 10 MW Pumped Storage Power Plant (Wewathenna) 350 MW	
2040	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 400 MW Wind 100 MW Mini Hydro 10 MW Pumped Storage Power Plant (Wewathenna) 350 MW	
2041	Distribution Connected Embedded Solar 150 MW Grid Connected Solar 400 MW Wind-Offshore 500 MW Mini Hydro 10 MW Battery Energy Storage 200 MW/ 800MWh	Gas Turbine - Natural Gas & Hydrogen Blend 200 MW *Retirement of* *Lakvijaya Coal Power Plant Unit 1 (300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2042	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	150 MW 400 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro Battery Energy Storage	150 MW 400 MW 500 MW 10 MW 200 MW/ 800MWh	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 350 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Gas Turbine - Natural Gas & Hydrogen Blend HVDC Interconnection *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	100 MW 300 MW 500 MW *(300) MW* *(300) MW*

Annex 8.4
Results of Generation Expansion Planning Studies 2025-2044

Scenario 5: Achieve 70% RE by 2030, increase to 80% from 2040 onwards, With aggressive Solar and BESS development, With 500 MW HVDC interconnection, No coal capacity additions

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass Battery Energy Storage	300 MW **50 MW** **10 MW** 10 MW 10 MW 5 MW/10 MWh	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	300 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	300 MW 250 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Southern Region)	300 MW 300 MW 200 MW 20 MW 20 MW 100 MW/ 400MWh	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	300 MW 300 MW 150 MW 20 MW 20 MW 100 MW/ 400MWh		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	300 MW 300 MW 150 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa**	**130 MW**
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage Battery Energy Storage	300 MW 200 MW 100 MW 20 MW 20 MW 100 MW/400 MWh 100 MW/800 MWh	*Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	 *(68) MW* *(72) MW* *(62) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	300 MW 200 MW 100 MW 20 MW 20 MW 200 MW/800 MWh		
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage Battery Energy Storage	300 MW 200 MW 100 MW 20 MW 20 MW 100 MW/ 400MWh 100 MW/ 800MWh	*Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	 *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pumped Storage Power Plant (Maha)	300 MW 200 MW 100 MW 20 MW 20 MW 600 MW		
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	300 MW 200 MW 100 MW 10 MW 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	300 MW 250 MW 100 MW 10 MW 10 MW		
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	300 MW 250 MW 100 MW 10 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	300 MW 250 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Battery Energy Storage	300 MW 250 MW 100 MW 10 MW 300 MW/ 2400MWh	HVDC Interconnection	500 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	300 MW 250 MW 100 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	300 MW 300 MW 10 MW 300 MW/ 2400MWh	Gas Turbine - Natural Gas & Hydrogen Blend *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	200 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a) (b) (d)]		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS [(a) (c) (e) (f)]	
2042	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	300 MW 300 MW 10 MW 200 MW/ 1600MWh	Gas Turbine - Natural Gas & Hydrogen Blend	100 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	300 MW 300 MW 500 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	300 MW 300 MW 10 MW 250 MW/1000 MWh	Nuclear Power Plant *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	600 MW *(300) MW* *(300) MW*

Annex 8.5
Results of Generation Expansion Planning Studies 2025-2044

Scenario 6: Maintain 65% RE from 2028 onwards, With coal capacity additions

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage**	150 MW **50 MW** **10 MW** 10 MW 10 MW **5 MW/10 MWh**	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	150 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 200 MW 20 MW 20 MW	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 100 MW 20 MW 20 MW		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	150 MW 100 MW 100 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa** Gas Turbine - Natural Gas	**130 MW** 200 MW
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 100 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	200 MW *(68) MW* *(72) MW* *(62) MW*
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 100 MW 20 MW 20 MW	Gas Turbine - Natural Gas	100 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 100 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	200 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pump Storage Power Plant (Maha)	150 MW 100 MW 100 MW 20 MW 20 MW 200 MW	Gas Turbine - Natural Gas	300 MW
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pump Storage Power Plant (Maha)	150 MW 100 MW 100 MW 10 MW 10 MW 200 MW	Coal Power Plant *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pump Storage Power Plant (Maha)	150 MW 100 MW 100 MW 10 MW 10 MW 200 MW	Gas Turbine - Natural Gas	100 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 100 MW 10 MW 10 MW	Gas Turbine - Natural Gas	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 100 MW 10 MW	Gas Turbine - Natural Gas Gas Turbine – Natural Gas	100 MW 300 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Battery Energy Storage	150 MW 250 MW 100 MW 10 MW 100 MW/ 400 MWh	Gas Turbine - Natural Gas	100 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 250 MW 100 MW 10 MW	Coal Power Plant Gas Turbine – Natural Gas *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	300 MW 300 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	150 MW 250 MW 10 MW 50 MW/ 200 MWh	Gas Turbine - Natural Gas	200 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	150 MW 250 MW 500 MW 10 MW	Gas Turbine - Natural Gas	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 250 MW 10 MW	Coal Power Plant Gas Turbine - Natural Gas *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	2x300 MW 200 MW *(300) MW* *(300) MW*

Annex 8.6
Results of Generation Expansion Planning Studies 2025-2044
Scenario 8: Maintain 60% RE from 2027 onwards, No coal capacity additions

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage**	150 MW **50 MW** **10 MW** 10 MW 10 MW **5 MW/10 MWh**	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	150 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* Extensions of plants to be retired Sapugaskanda Station A Sapugaskanda Station B Barge Mounted Plant	**235 MW** *(115) MW* 68 MW 72 MW 62 MW
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 20 MW 50 MW 20 MW 20 MW	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 20 MW 50 MW 20 MW 20 MW		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	150 MW 20 MW 50 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa** Gas Turbine - Natural Gas	**130 MW** 200 MW
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	200 MW *(68) MW* *(72) MW* *(62) MW*
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas	200 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	100 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 20 MW 20 MW	Gas Turbine - Natural Gas	2x300 MW
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 50 MW 75 MW 10 MW 10 MW	Combined Cycle Power Plant - Natural Gas *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 75 MW 10 MW 10 MW	Gas Turbine - Natural Gas	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 100 MW 75 MW 10 MW 10 MW	Gas Turbine - Natural Gas	300 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 100 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 100 MW 100 MW 10 MW	Gas Turbine - Natural Gas	300 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pump Storage Power Plant (Maha)	150 MW 100 MW 100 MW 10 MW 200 MW	Gas Turbine - Natural Gas	100 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pump Storage Power Plant (Maha)	150 MW 200 MW 100 MW 10 MW 200 MW	Combined Cycle Power Plant - Natural Gas *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	400 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Pump Storage Power Plant (Maha)	150 MW 200 MW 100 MW 10 MW 200 MW		
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 125 MW 10 MW	Combined Cycle Power Plant - Natural Gas	400 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a) (b)		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS (a) (c)	
2044	Distribution Connected Embedded Solar	150 MW	Gas Turbine - Natural Gas	100 MW
	Grid Connected Solar	200 MW	Combined Cycle Power Plant - Natural Gas	400 MW
	Wind	200 MW		
	Mini Hydro	10 MW	*Retirements of*	
			Lakvijaya Coal Power Plant Unit 2	*(300) MW*
			Lakvijaya Coal Power Plant Unit 3	*(300) MW*

Annex 10.1

Capacity Balance for Base Case Scenario of LTGEP 2025-2044

Plant Name	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Renewables																				
Major Hydro	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563
Mini Hydro	429	439	449	469	489	509	529	549	569	589	599	609	619	629	639	649	659	669	679	689
Biomass	64	79	99	119	139	159	179	199	219	239	249	259	269	269	269	269	269	269	269	269
Wind	277	367	627	827	977	1,127	1,227	1,327	1,427	1,527	1,627	1,727	1,827	1,927	2,027	2,127	2,127	2,127	2,627	2,627
Solar	1,312	1,682	2,082	2,532	2,982	3,432	3,782	4,132	4,482	4,832	5,182	5,582	5,982	6,382	6,782	7,182	7,632	8,082	8,532	8,982
Sub Total	3,645	4,130	4,820	5,510	6,150	6,790	7,280	7,770	8,260	8,750	9,220	9,740	10,260	10,770	11,280	11,790	12,250	12,710	13,670	14,130
Thermal Existing and NG Conversions																				
Sapugaskanda A	68	68	68	68	68	68	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sapugaskanda B	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Turbine No7	115	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kelanitissa Combined Cycle 1	161	161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kelanitissa Combined Cycle 2	155	155	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Westcoast Combined Cycle	270	270	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakvijaya Coal	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	540	540	540	-
Uthurujanani	27	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-	-	-	-	-
CEB Barge Power	62	62	62	62	62	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dakunujanani & Mathugama DPS	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-
NG Converted Kelanitissa Combined Cycle 1	-	-	161	161	161	161	161	161	-	-	-	-	-	-	-	-	-	-	-	-
NG Converted Kelanitissa Combined Cycle 2	-	-	155	155	155	155	155	155	-	-	-	-	-	-	-	-	-	-	-	-
NG Converted Westcoast Combined Cycle	-	-	270	270	270	270	270	270	270	270	-	-	-	-	-	-	-	-	-	-
Sub Total	1,790	1,675	1,675	1,675	1,675	1,675	1,472	1,472	1,130	1,130	860	860	860	810	810	810	540	540	540	-
New and Committed Thermal Plants																				
New NG Combined Cycles[1]	312	524	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
Kerawalapitiya NG IC Engines[1]	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Kelanitissa New NG Gas Turbines	-	-	-	-	-	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
New NG Gas Turbines	-	-	-	-	-	-	106	106	213	213	213	213	213	213	213	213	213	213	213	213
New NG/H_2 Gas Turbines	-	-	-	-	-	-	-	-	-	-	289	577	770	770	770	963	1,445	1,733	1,733	1,926
New NG/H_2 IC Engines	-	-	-	-	-	-	-	-	-	-	-	-	-	203	203	203	203	203	405	405
Nuclear Power Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	552
Sub Total	312	524	700	900	900	1,030	1,137	1,137	1,243	1,243	1,532	1,820	2,013	2,216	2,216	2,409	2,890	3,179	3,381	4,126
Interconnections																				
HVDC Interconnection with India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500	500	500	500	500
Sub Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	500	500	500	500	500	500
Energy Storage																				
BESS	5	105	105	205	305	355	455	655	755	755	750	750	850	850	850	850	850	850	850	900
PSPP	-	-	-	-	-	-	-	-	-	600	600	600	600	600	600	600	600	600	600	600
Sub Total	5	105	105	205	305	355	455	655	755	1,355	1,350	1,350	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,500
Installed Capacity	**5,752**	**6,434**	**7,300**	**8,290**	**9,030**	**9,850**	**10,344**	**11,034**	**11,388**	**12,478**	**12,962**	**13,770**	**14,583**	**15,246**	**16,256**	**16,959**	**17,630**	**18,379**	**19,541**	**20,256**
System Demand	**2,727**	**2,872**	**3,027**	**3,190**	**3,362**	**3,548**	**3,722**	**3,904**	**4,094**	**4,294**	**4,507**	**4,738**	**4,985**	**5,247**	**5,516**	**5,798**	**6,095**	**6,397**	**6,706**	**7,026**

Notes

All capacities are at the end of the year and in MW (Net)

Maintenance and forced outages are not considered.

"New NG Combined Cycles" represents Sobadhanavi NG combined cycle power plant and Kerawalapitiya second NG combined cycle power plant

[1]Plants will operate on Diesel up to June 2027 until LNG supply made available

Annex 10.2

Energy Balance for Base Case Scenario of LTGEP 2025-2044

Plant Name	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Renewables																				
Major Hydro	5,266	5,220	4,788	5,379	5,161	5,445	5,507	5,042	5,212	5,075	5,298	5,239	5,110	5,215	4,950	5,279	5,160	5,107	5,168	5,304
Mini Hydro	1,330	1,361	1,386	1,436	1,476	1,512	1,556	1,612	1,660	1,777	1,792	1,807	1,828	1,833	1,913	1,933	1,961	1,972	1,984	2,010
Biomass	300	368	447	505	544	585	632	695	749	932	952	965	992	952	1,068	1,061	1,050	1,025	991	993
Wind	869	1,154	2,078	2,745	3,238	3,566	3,914	4,321	4,647	5,039	5,248	5,409	5,768	6,165	6,745	6,979	6,843	7,082	8,148	8,330
Solar	2,061	2,747	3,360	4,149	4,906	5,452	5,996	6,524	7,009	8,038	8,683	9,308	9,946	10,487	11,510	12,030	12,872	13,680	14,268	14,810
Sub Total	9,827	10,849	12,059	14,214	15,326	16,560	17,606	18,195	19,277	20,860	21,972	22,728	23,644	24,653	26,185	27,282	27,888	28,865	30,559	31,448
Thermal Existing and NG Conversions																				
Sapugaskanda A	108	147	52	2	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sapugaskanda B	316	258	112	6	6	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Turbine No7	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kelanitissa Combined Cycle 1	998	768	390	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kelanitissa Combined Cycle 2	2	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Westcoast Combined Cycle	165	387	37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakvijaya Coal	5,737	5,640	5,401	4,971	4,759	4,777	4,842	4,968	5,131	5,189	5,099	5,328	5,516	5,563	5,441	5,475	3,595	3,973	3,793	-
Uthurujanani	90	66	26	2	2	2	1	1	-	-	-	-	-	-	-	-	-	-	-	-
CEB Barge Power	286	217	92	1	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dakunujanani & Mathugama DPS	2	4	1	0	0	0	0	0	0	0	0	1	0	-	-	-	-	-	-	-
NG Converted Kelanitissa Combined Cycle 1	-	-	29	29	7	14	7	25	3	-	-	-	-	-	-	-	-	-	-	-
NG Converted Kelanitissa Combined Cycle 2	-	-	-	15	1	3	10	2	-	-	-	-	-	-	-	-	-	-	-	-
NG Converted Westcoast Combined Cycle	-	-	83	57	55	54	56	85	95	129	41	-	-	-	-	-	-	-	-	-
Sub Total	7,705	7,525	6,222	5,083	4,832	4,856	4,916	5,082	5,229	5,319	5,140	5,329	5,517	5,563	5,441	5,475	3,595	3,973	3,793	-
New and Committed Thermal Plants																				
New NG Combined Cycles[1]	180	264	1,347	1,284	1,527	1,379	1,407	1,788	1,745	1,739	2,104	2,444	2,611	2,852	2,415	2,722	4,263	4,419	4,549	4,564
Kerawalapitiya NG IC Engines	-	-	-	105	119	173	171	238	260	232	279	344	461	511	347	426	809	844	953	974
Kelanitissa New NG Gas Turbines	-	-	-	-	-	29	27	29	43	36	52	106	183	193	85	128	371	417	452	469
New NG Gas Turbines	-	-	-	-	-	-	6	5	12	22	27	82	168	168	41	79	297	399	310	363
New NG/H_2 Gas Turbines	-	-	-	-	-	-	-	-	-	-	5	30	97	105	13	52	289	498	453	661
New NG/H_2 IC Engines	-	-	-	-	-	-	-	-	-	-	-	-	-	266	112	170	497	561	1,072	1,151
Nuclear Power Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,399
Sub Total	180	264	1,347	1,389	1,646	1,582	1,612	2,060	2,060	2,029	2,467	3,006	3,519	4,095	3,014	3,576	6,526	7,138	7,791	12,581
Interconnections																				
HVDC Interconnection with India - Net Imp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,316	1,401	1,587	1,526	1,272	1,376
Sub Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,316	1,401	1,587	1,526	1,272	1,376
Total Generation	**17,712**	**18,638**	**19,628**	**20,686**	**21,804**	**22,997**	**24,133**	**25,337**	**26,565**	**28,208**	**29,579**	**31,063**	**32,681**	**34,310**	**35,956**	**37,735**	**39,596**	**41,503**	**43,414**	**45,405**
System Demand	**17,725**	**18,650**	**19,630**	**20,662**	**21,750**	**22,927**	**24,026**	**25,174**	**26,369**	**27,624**	**28,961**	**30,411**	**31,953**	**33,594**	**35,275**	**37,038**	**38,892**	**40,767**	**42,689**	**44,673**
BESS & PSPP Net Generation	**0**	**0**	**(1)**	**(25)**	**(56)**	**(69)**	**(105)**	**(162)**	**(194)**	**(580)**	**(613)**	**(648)**	**(720)**	**(710)**	**(672)**	**(686)**	**(697)**	**(725)**	**(715)**	**(721)**

Notes

Energy figures are in GWh

Numbers may not add exactly due to rounding off error

Net generation figures have deviation from demand forecast figures as energy balance is developed based on simulation results.

All energy figures are shown for weighted average hydrological condition

"New NG Combined Cycles" represents Sobadhanavi NG combined cycle power plant and Kerawalapitiya second NG combined cycle power plant

[1] Plants will operate on Diesel up to June 2027 until LNG supply is made available

Annex 10.3

Annual Energy Generation and Plant Factors

Year	Plant Name	Capacity (MW)	Annual Energy (GWh)			Annual Plant Factor		
			Low RE	Avg RE	High RE	Low RE	Avg RE	High RE
2025	**Renewable Energy (Major Hydro+ORE)**	**1,563**	**8,715**	**9,827**	**10,605**			
	Sapugaskanda A	4x17	217	108	72	36%	18%	12%
	Sapugaskanda B	8x9	455	316	203	72%	50%	32%
	Gas Turbine No7	1x115	2	2	3	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	1,128	998	663	80%	71%	47%
	Kelanitissa Combined Cycle 2	1x155	18	2	0	1%	0%	0%
	Westcoast Combined Cycle	1x270	631	165	94	27%	7%	4%
	Lakvijaya Coal	3x270	5,768	5,737	5,681	81%	81%	80%
	Uthurujanani	3x8.9	145	90	39	62%	38%	17%
	CEB Barge Power	4x15.6	409	286	147	75%	52%	27%
	Dakunujanani & Mathugama DPS	50x1	2	2	4	0%	1%	1%
	New NG Combined Cycles	1x312	230	180	199	8%	7%	7%
	Total Thermal Generation		**9,003**	**7,885**	**7,105**			
	Total Generation		**17,719**	**17,712**	**17,710**			

2026	**Renewable Energy (Major Hydro+ORE)**	**4,130**	**9,461**	**10,849**	**12,057**			
	Sapugaskanda A	4x17	286	147	80	48%	25%	13%
	Sapugaskanda B	8x9	447	258	141	71%	41%	22%
	Kelanitissa Combined Cycle 1	1x161	982	768	584	70%	55%	41%
	Kelanitissa Combined Cycle 2	1x155	47	38	14	3%	3%	1%
	Westcoast Combined Cycle	1x270	762	387	157	32%	16%	7%
	Lakvijaya Coal	3x270	5,739	5,640	5,218	81%	79%	74%
	Uthurujanani	3x8.9	145	66	27	62%	28%	12%
	CEB Barge Power	4x15.6	392	217	101	72%	40%	18%
	Dakunujanani & Mathugama DPS	50x1	3	4	5	1%	1%	1%
	New NG Combined Cycles	1x312+1x212	382	264	254	8%	6%	6%
	Total Thermal Generation		**9,185**	**7,789**	**6,581**			
	Total Generation		**18,645**	**18,638**	**18,638**			

2027	**Renewable Energy (Major Hydro+ORE)**	**4,820**	**11,174**	**12,059**	**13,699**			
	Sapugaskanda A	4x17	105	52	37	18%	9%	6%
	Sapugaskanda B	8x9	158	112	63	25%	18%	10%
	Kelanitissa Combined Cycle 1	1x161	448	419	328	32%	30%	23%
	Kelanitissa Combined Cycle 2	1x155	-	0	-	0%	0%	0%
	Westcoast Combined Cycle	1x270	335	120	46	14%	5%	2%
	Lakvijaya Coal	3x270	5,559	5,401	4,687	78%	76%	66%
	Uthurujanani	3x8.9	41	26	10	17%	11%	4%
	CEB Barge Power	4x15.6	129	92	35	24%	17%	6%
	Dakunujanani & Mathugama DPS	50x1	0	1	1	0%	0%	0%
	New NG Combined Cycles	2x350	1,680	1,347	719	27%	22%	12%
	Total Thermal Generation		**8,456**	**7,569**	**5,927**			
	Total Generation		**19,630**	**19,628**	**19,626**			

Year	Plant Name	Capacity (MW)	Annual Energy (GWh)			Annual Plant Factor		
			Low RE	Avg RE	High RE	Low RE	Avg RE	High RE
2028	**Renewable Energy (Major Hydro+ORE)**	**5,510**	**13,275**	**14,214**	**15,183**			
	Sapugaskanda A	4x17	2	2	2	0%	0%	0%
	Sapugaskanda B	8x9	5	6	5	1%	1%	1%
	Lakvijaya Coal	3x270	5,256	4,971	4,453	74%	70%	63%
	Uthurujanani	3x8.9	1	2	2	1%	1%	1%
	CEB Barge Power	4x15.6	0	1	1	0%	0%	0%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	33	29	25	2%	2%	2%
	Kelanitissa Combined Cycle 2	1x155	16	15	6	1%	1%	0%
	Westcoast Combined Cycle	1x270	72	57	38	3%	2%	2%
	New NG Combined Cycles	2x350	1,829	1,284	872	30%	21%	14%
	Kerawalapitiya NG IC Engines	1x200	198	105	104	11%	6%	6%
	Total Thermal Generation		**7,412**	**6,472**	**5,508**			
	Total Generation		**20,687**	**20,686**	**20,690**			

2029	**Renewable Energy (Major Hydro+ORE)**	**6,150**	**14,378**	**15,326**	**16,420**			
	Sapugaskanda A	4x17	1	1	1	0%	0%	0%
	Sapugaskanda B	8x9	5	6	5	1%	1%	1%
	Lakvijaya Coal	3x270	5,121	4,759	4,073	72%	67%	57%
	Uthurujanani	3x8.9	1	2	2	1%	1%	1%
	CEB Barge Power	4x15.6	1	1	0	0%	0%	0%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	4	7	10	0%	0%	1%
	Kelanitissa Combined Cycle 2	1x155	1	1	1	0%	0%	0%
	Westcoast Combined Cycle	1x270	82	55	35	3%	2%	1%
	New NG Combined Cycles	2x350	2,009	1,527	1,166	33%	25%	19%
	Kerawalapitiya NG IC Engines	1x200	201	119	96	11%	7%	5%
	Total Thermal Generation		**7,427**	**6,478**	**5,389**			
	Total Generation		**21,805**	**21,804**	**21,809**			

2030	**Renewable Energy (Major Hydro+ORE)**	**6,790**	**15,342**	**16,560**	**17,849**			
	Sapugaskanda A	4x17	0	1	1	0%	0%	0%
	Sapugaskanda B	8x9	3	5	4	1%	1%	1%
	Lakvijaya Coal	3x270	5,222	4,777	3,999	74%	67%	56%
	Uthurujanani	3x8.9	1	2	2	1%	1%	1%
	CEB Barge Power	4x15.6	-	0	1	0%	0%	0%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	15	14	10	1%	1%	1%
	Kelanitissa Combined Cycle 2	1x155	-	3	2	0%	0%	0%
	Westcoast Combined Cycle	1x270	92	54	33	4%	2%	1%
	New NG Combined Cycles	2x350	2,060	1,379	949	34%	22%	15%
	Kerawalapitiya NG IC Engines	1x200	228	173	122	13%	10%	7%
	Kelanitissa New NG Gas Turbines	1x130	26	29	27	2%	3%	2%
	Total Thermal Generation		**7,648**	**6,438**	**5,150**			
	Total Generation		**22,990**	**22,997**	**22,999**			

2031	**Renewable Energy (Major Hydro+ORE)**	**7,280**	**16,183**	**17,606**	**18,487**			
	Lakvijaya Coal	3x270	5,246	4,842	4,246	74%	68%	60%
	Uthurujanani	3x8.9	1	1	2	1%	1%	1%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	23	7	6	2%	0%	0%
	Kelanitissa Combined Cycle 2	1x155	45	10	3	3%	1%	0%
	Westcoast Combined Cycle	1x270	182	56	31	8%	2%	1%
	New NG Combined Cycles	2x350	2,073	1,407	1,163	34%	23%	19%
	Kerawalapitiya NG IC Engines	1x200	309	171	168	18%	10%	10%
	Kelanitissa New NG Gas Turbines	1x130	60	27	26	5%	2%	2%
	New NG Gas Turbines	1x106	6	6	6	1%	1%	1%
	Total Thermal Generation		**7,945**	**6,527**	**5,651**			
	Total Generation		**24,128**	**24,133**	**24,138**			

Year	Plant Name	Capacity (MW)	Annual Energy (GWh)			Annual Plant Factor		
			Low RE	Avg RE	High RE	Low RE	Avg RE	High RE
2032	**Renewable Energy (Major Hydro+ORE)**	**7,770**	**17,265**	**18,195**	**19,045**			
	Lakvijaya Coal	3x270	5,315	4,968	4,939	75%	70%	70%
	Uthurujanani	3x8.9	1	1	1	0%	0%	0%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	88	25	19	6%	2%	1%
	Kelanitissa Combined Cycle 2	1x155	10	2	-	1%	0%	0%
	Westcoast Combined Cycle	1x270	203	85	33	9%	4%	1%
	New NG Combined Cycles	2x350	2,006	1,788	1,085	33%	29%	18%
	Kerawalapitiya NG IC Engines	1x200	378	238	189	22%	14%	11%
	Kelanitissa New NG Gas Turbines	1x130	69	29	26	6%	3%	2%
	New NG Gas Turbines	1x106	9	5	5	1%	1%	1%
	Total Thermal Generation		**8,078**	**7,142**	**6,297**			
	Total Generation		**25,342**	**25,337**	**25,342**			
2033	**Renewable Energy (Major Hydro+ORE)**	**8,260**	**18,186**	**19,277**	**20,053**			
	Lakvijaya Coal	3x270	5,335	5,131	4,674	75%	72%	66%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Kelanitissa Combined Cycle 1	1x161	25	3	-	2%	0%	0%
	Kelanitissa Combined Cycle 2	1x155	-	-	-	0%	0%	0%
	Westcoast Combined Cycle	1x270	182	95	80	8%	4%	3%
	New NG Combined Cycles	2x350	2,370	1,745	1,477	39%	28%	24%
	Kerawalapitiya NG IC Engines	1x200	379	260	234	22%	15%	13%
	Kelanitissa New NG Gas Turbines	1x130	65	43	44	6%	4%	4%
	New NG Gas Turbines	2x106	16	12	12	1%	1%	1%
	Total Thermal Generation		**8,373**	**7,288**	**6,522**			
	Total Generation		**26,559**	**26,565**	**26,575**			
2034	**Renewable Energy (Major Hydro+ORE)**	**8,750**	**19,343**	**20,860**	**22,372**			
	Lakvijaya Coal	3x270	5,425	5,189	4,444	76%	73%	63%
	Dakunujanani & Mathugama DPS	50x1	3	0	0	1%	0%	0%
	Westcoast Combined Cycle	1x270	305	129	76	13%	5%	3%
	New NG Combined Cycles	2x350	2,518	1,739	1,130	41%	28%	18%
	Kerawalapitiya NG IC Engines	1x200	385	232	172	22%	13%	10%
	Kelanitissa New NG Gas Turbines	1x130	89	36	20	8%	3%	2%
	New NG Gas Turbines	2x100	103	22	15	6%	1%	1%
	Total Thermal Generation		**8,828**	**7,347**	**5,858**			
	Total Generation		**28,171**	**28,208**	**28,230**			
2035	**Renewable Energy (Major Hydro+ORE)**	**9,220**	**20,826**	**21,972**	**23,227**			
	Lakvijaya Coal	3x270	5,387	5,099	4,850	76%	72%	68%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	Westcoast Combined Cycle	1x270	87	41	-	4%	2%	0%
	New NG Combined Cycles	2x350	2,652	2,104	1,329	43%	34%	22%
	Kerawalapitiya NG IC Engines	1x200	425	279	149	24%	16%	8%
	Kelanitissa New NG Gas Turbines	1x130	122	52	27	11%	5%	2%
	New NG Gas Turbines	2x106	77	27	15	4%	1%	1%
	New NG/H_2 Gas Turbines	1x289	10	5	1	0%	0%	0%
	Total Thermal Generation		**8,760**	**7,607**	**6,370**			
	Total Generation		**29,586**	**29,579**	**29,597**			

Year	Plant Name	Capacity (MW)	Annual Energy (GWh)			Annual Plant Factor		
			Low RE	Avg RE	High RE	Low RE	Avg RE	High RE
2036	**Renewable Energy (Major Hydro+ORE)**	**9,740**	**21,821**	**22,728**	**23,928**			
	Lakvijaya Coal	3x270	5,465	5,328	4,831	77%	75%	68%
	Dakunujanani & Mathugama DPS	50x1	2	1	0	0%	0%	0%
	New NG Combined Cycles	2x350	2,997	2,444	1,870	49%	40%	30%
	Kerawalapitiya NG IC Engines	1x200	481	344	297	29%	20%	17%
	Kelanitissa New NG Gas Turbines	1x130	139	106	77	21%	9%	7%
	New NG Gas Turbines	2x106	134	82	53	14%	4%	3%
	New NG/H_2 Gas Turbines	2x289	28	30	13	3%	1%	0%
	Total Thermal Generation		**9,246**	**8,334**	**7,141**			
	Total Generation		**31,066**	**31,063**	**31,069**			

2037	**Renewable Energy (Major Hydro+ORE)**	**10,260**	**22,989**	**23,644**	**24,656**			
	Lakvijaya Coal	3x270	5,662	5,516	5,235	80%	78%	74%
	Dakunujanani & Mathugama DPS	50x1	0	0	0	0%	0%	0%
	New NG Combined Cycles	2x350	2,861	2,611	2,212	47%	43%	36%
	Kerawalapitiya NG IC Engines	1x200	509	461	340	29%	26%	19%
	Kelanitissa New NG Gas Turbines	1x130	237	183	140	21%	16%	12%
	New NG Gas Turbines	2x106	257	168	104	14%	9%	6%
	New NG/H_2 Gas Turbines	2x289+1x193	177	97	32	3%	1%	0%
	Total Thermal Generation		**9,703**	**9,036**	**8,063**			
	Total Generation		**32,692**	**32,681**	**32,719**			

2038	**Renewable Energy (Major Hydro+ORE)**	**10,770**	**23,201**	**24,653**	**25,729**			
	Lakvijaya Coal	3x270	5,682	5,563	5,465	80%	78%	77%
	New NG Combined Cycles	2x350	3,427	2,852	2,319	56%	47%	38%
	Kerawalapitiya NG IC Engines	1x200	679	511	360	39%	29%	21%
	Kelanitissa New NG Gas Turbines	1x130	295	193	132	26%	17%	12%
	New NG Gas Turbines	2x106	277	168	95	15%	9%	5%
	New NG/H_2 Gas Turbines	2x289+1x193	318	105	46	5%	2%	1%
	New NG/H_2 IC Engines	1x203	400	266	179	23%	15%	10%
	Total Thermal Generation		**11,077**	**9,657**	**8,596**			
	Total Generation		**34,278**	**34,310**	**34,325**			

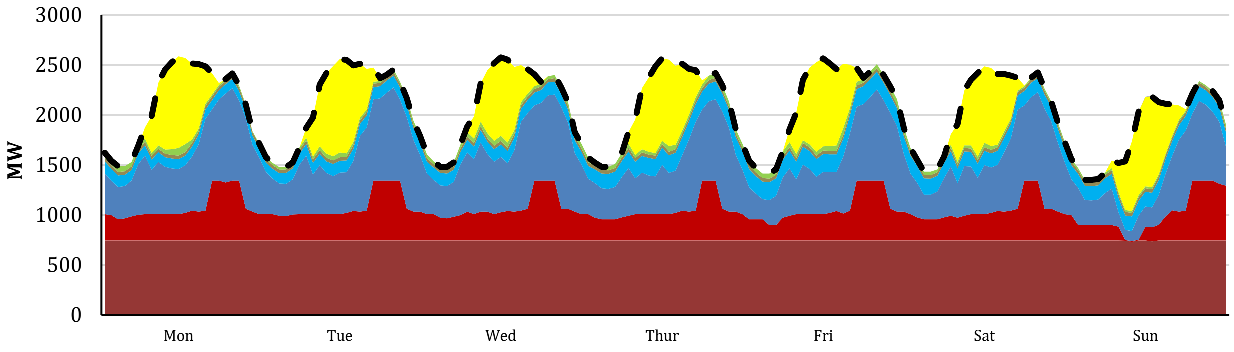
2039	**Renewable Energy (Major Hydro+ORE)**	**11,280**	**24,883**	**26,185**	**27,092**			
	Lakvijaya Coal	3x270	5,497	5,441	5,343	77%	77%	75%
	New NG Combined Cycles	2x350	2,848	2,415	1,878	46%	39%	31%
	Kerawalapitiya NG IC Engines	1x200	478	347	227	27%	20%	13%
	Kelanitissa New NG Gas Turbines	1x130	144	85	51	13%	7%	4%
	New NG Gas Turbines	2x106	111	41	21	6%	2%	1%
	New NG/H_2 Gas Turbines	2x289+1x193	51	13	7	1%	0%	0%
	New NG/H_2 IC Engines	1x203	196	112	67	11%	6%	4%
	Total Thermal Generation		**9,323**	**8,455**	**7,593**			
	Total Generation		**34,207**	**34,640**	**34,686**			

2040	**Renewable Energy (Major Hydro+ORE)**	**11,790**	**26,366**	**27,282**	**28,071**			
	Lakvijaya Coal	3x270	5,516	5,475	5,541	78%	77%	78%
	New NG Combined Cycles	2x350	3,257	2,722	23,64	53%	44%	39%
	Kerawalapitiya NG IC Engines	1x200	517	426	358	29%	24%	20%
	Kelanitissa New NG Gas Turbines	1x130	206	128	87	18%	11%	8%
	New NG Gas Turbines	2x106	99	79	54	5%	4%	3%
	New NG/H_2 Gas Turbines	2x289+2x193	47	52	41	1%	1%	0%
	New NG/H_2 IC Engines	1x203	269	170	122	15%	10%	7%
	Total Thermal Generation		**9,911**	**9,052**	**8,567**			
	Total Generation		**36,277**	**36,334**	**36,638**			

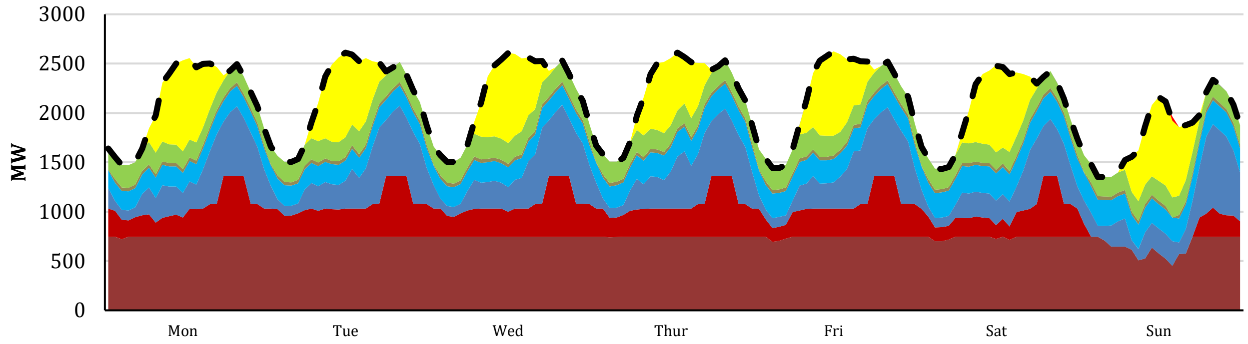
Year	Plant Name	Capacity (MW)	Annual Energy (GWh)			Annual Plant Factor		
			Low RE	Avg RE	High RE	Low RE	Avg RE	High RE
2041	**Renewable Energy (Major Hydro+ORE)**	**12,250**	**26,494**	**27,888**	**28,539**			
	Lakvijaya Coal	2x270	3,608	3,595	3,594	76%	76%	76%
	New NG Combined Cycles	2x350	4,672	4,263	4,035	76%	70%	66%
	Kerawalapitiya NG IC Engines	1x200	974	809	739	56%	46%	42%
	Kelanitissa New NG Gas Turbines	1x130	492	371	346	43%	33%	30%
	New NG Gas Turbines	2x106	484	297	241	26%	16%	13%
	New NG/H_2 Gas Turbines	3x289+3x193	551	289	215	4%	2%	2%
	New NG/H_2 IC Engines	1x203	667	497	405	38%	28%	23%
	Total Thermal Generation		**11,449**	**10,121**	**9,575**			
	Total Generation		**37,943**	**38,009**	**38,114**			
2042	**Renewable Energy (Major Hydro+ORE)**	**12,710**	**27,837**	**28,865**	**30,032**			
	Lakvijaya Coal	2x270	3,971	3,973	3,959	84%	84%	84%
	New NG Combined Cycles	2x350	4,713	4,419	3,744	77%	72%	61%
	Kerawalapitiya NG IC Engines	1x200	983	844	751	56%	48%	43%
	Kelanitissa New NG Gas Turbines	1x130	525	417	364	46%	37%	32%
	New NG Gas Turbines	2x106	505	399	332	27%	21%	18%
	New NG/H_2 Gas Turbines	4x289+3x193	622	498	358	4%	3%	2%
	New NG/H_2 IC Engines	1x203	693	561	477	39%	32%	27%
	Total Thermal Generation		**12,012**	**11,111**	**9,985**			
	Total Generation		**39,848**	**39,976**	**40,017**			
2043	**Renewable Energy (Major Hydro+ORE)**	**13,670**	**29,560**	**30,559**	**32,009**			
	Lakvijaya Coal	2x270	3,797	3,793	3,752	80%	80%	79%
	New NG Combined Cycles	2x350	4,786	4,549	3,787	78%	74%	62%
	Kerawalapitiya NG IC Engines	1x200	1,139	953	809	65%	54%	46%
	Kelanitissa New NG Gas Turbines	1x130	546	452	376	48%	40%	33%
	New NG Gas Turbines	2x106	386	310	274	21%	17%	15%
	New NG/H_2 Gas Turbines	4x289+3x193	558	453	386	4%	3%	3%
	New NG/H_2 IC Engines	2x203	1,355	1,072	913	38%	30%	26%
	Total Thermal Generation		**12,567**	**11,583**	**10,296**			
	Total Generation		**42,128**	**42,142**	**42,305**			
2044	**Renewable Energy (Major Hydro+ORE)**	**14,130**	**29,733**	**31,448**	**33,001**			
	New NG Combined Cycles	2x350	4,822	4,564	4,170	79%	74%	68%
	Kerawalapitiya NG IC Engines	1x200	1,182	974	813	67%	56%	46%
	Kelanitissa New NG Gas Turbines	1x130	620	469	357	54%	41%	31%
	New NG Gas Turbines	2x106	466	363	235	25%	19%	13%
	New NG/H_2 Gas Turbines	5x289+3x193	933	661	455	6%	4%	3%
	New NG/H_2 IC Engines	2x203	1,613	1,151	830	45%	32%	23%
	Nuclear Power Plant	1x552	4,399	4,399	4,398	91%	91%	91%
	Total Thermal Generation		**14,035**	**12,581**	**11,259**			
	Total Generation		**43,768**	**44,029**	**44,260**			

Weekly System Dispatch 2025

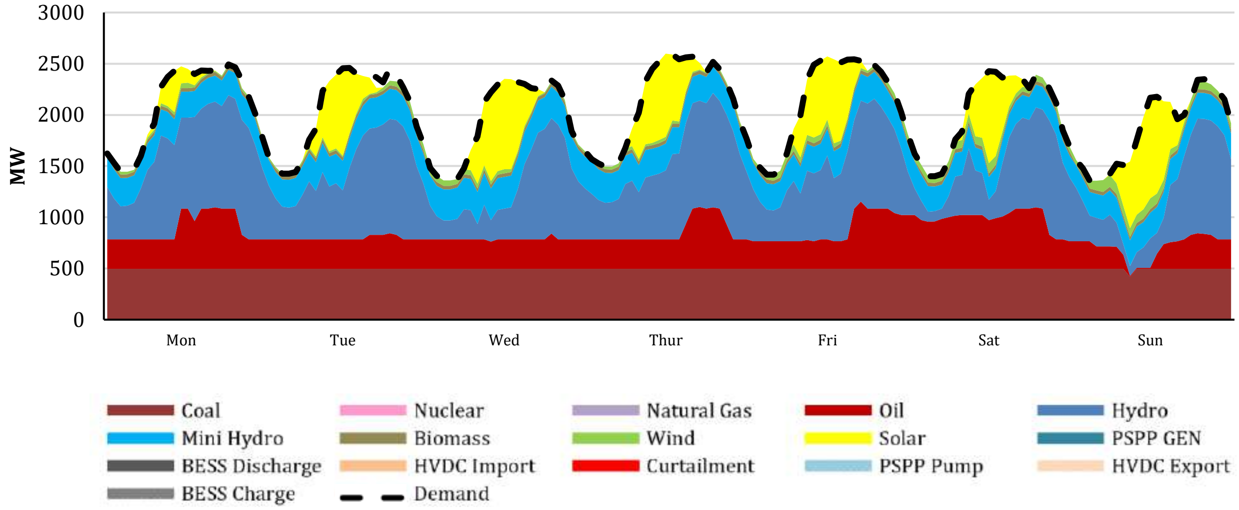
Dry Season (January to April)



High Wind Season (May to September)

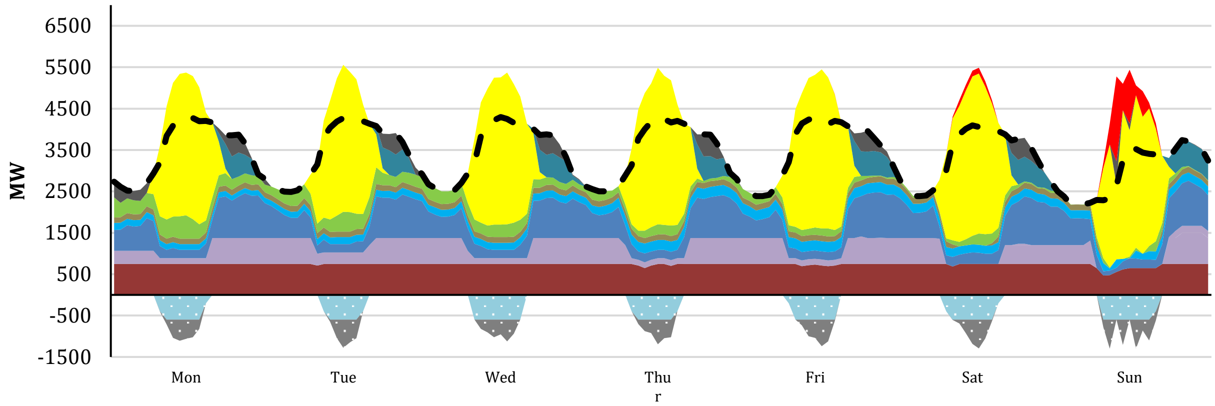


Wet Season (October to December)

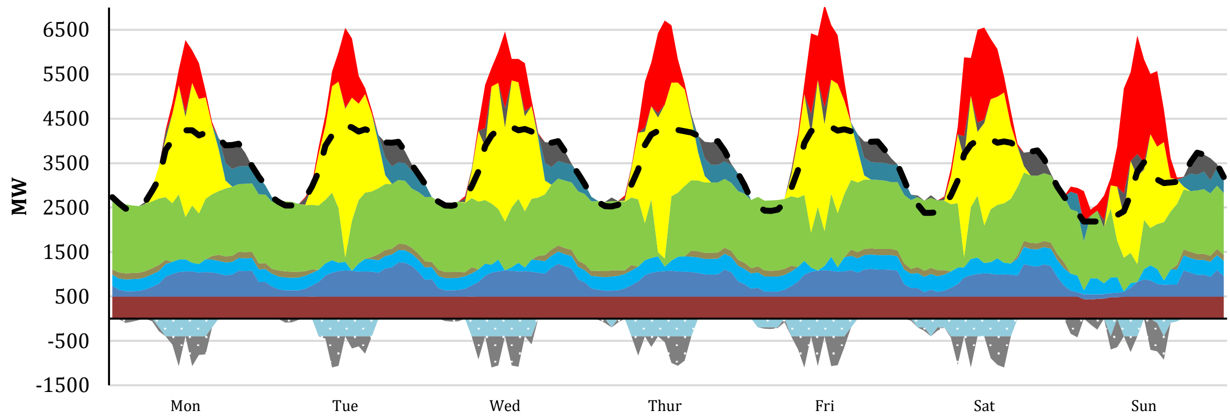


Weekly System Dispatch 2035

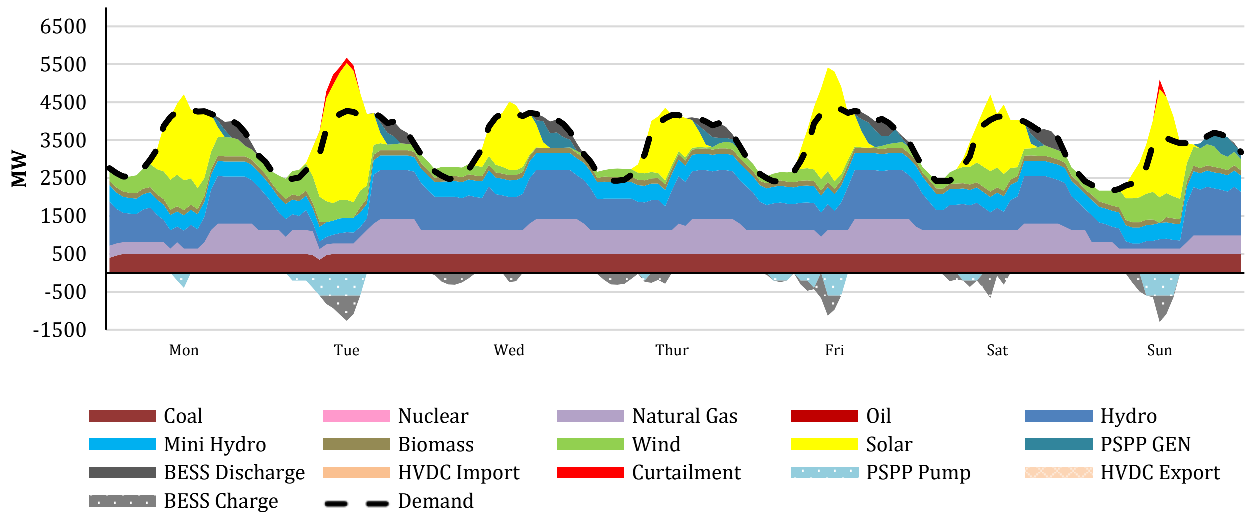
Dry Season (January to April)



High Wind Season (May to September)

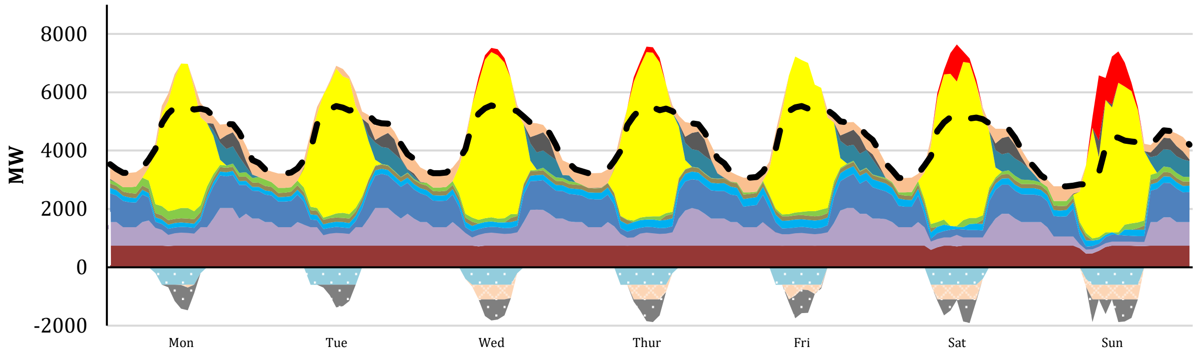


Wet Season (October to December)

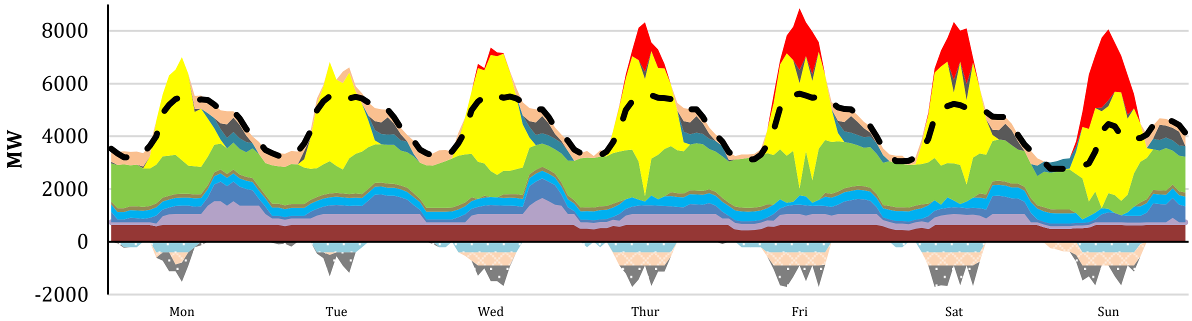


Weekly System Dispatch 2040

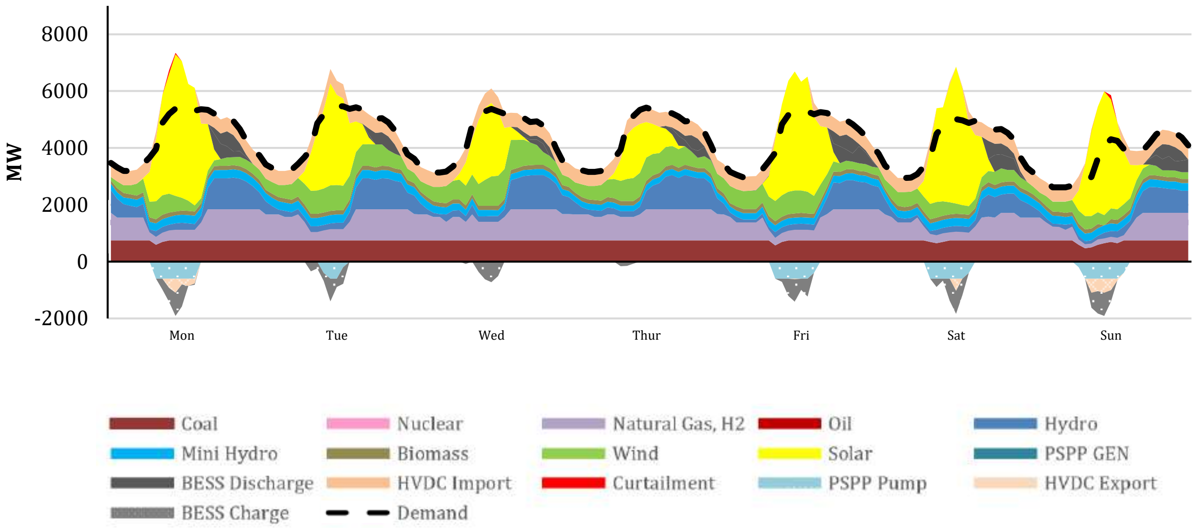
Dry Season (January to April)



High Wind Season (May to September)



Wet Season (October to December)



Annex 10.7

Fuel Requirement and Expenditure on Fuel – Base Case Scenario

Year	Auto Diesel		Fuel Oil		Naptha		Coal		Natural Gas		H_2		Nuclear Fuel	
	1000 MT	Million USD	1000 MT	Million USD	1000 MT	Million USD	1000 MT	Million USD	1000 MT	Million USD	1000 MT	Million USD	1000 MT	Million USD
2025	41.7	35.1	203.4	158.8	174.5	145.3	2,444	325.2	-	-	-	-	-	-
2026	69.4	58.3	231.2	180.5	134.4	111.9	2,406	320.1	-	-	-	-	-	-
2027	59.6	50.1	67.1	52.4	68.3	56.8	2,300	305.9	194.9	112.6	-	-	-	-
2028	0.1	0.1	2.2	1.7	-	-	2,127	282.9	245.1	141.5	-	-	-	-
2029	0.1	0.1	1.9	1.5	-	-	2,037	270.9	277.8	160.4	-	-	-	-
2030	0.1	0.1	1.6	1.3	-	-	2,031	270.2	270.0	155.9	-	-	-	-
2031	0.1	0.1	0.3	0.2	-	-	2,070	275.4	275.1	158.8	-	-	-	-
2032	0.1	0.1	0.2	0.2	-	-	2,121	282.2	355.0	205.0	-	-	-	-
2033	0.0	0.0	-	-	-	-	2,181	290.2	353.3	204.0	-	-	-	-
2034	0.1	0.1	-	-	-	-	2,214	294.5	354.8	204.9	-	-	-	-
2035	0.0	0.0	-	-	-	-	2,176	289.5	410.2	236.8	0.0	0.2	-	-
2036	0.1	0.1	-	-	-	-	2,259	300.4	497.1	287.0	0.3	1.5	-	-
2037	0.1	0.1	-	-	-	-	2,352	312.8	593.2	342.5	1.0	5.0	-	-
2038	-	-	-	-	-	-	2,372	315.5	685.4	395.8	2.6	12.8	-	-
2039	-	-	-	-	-	-	2,309	307.2	494.4	285.5	0.8	3.8	-	-
2040	-	-	-	-	-	-	2,336	310.7	592.4	342.1	1.5	7.5	-	-
2041	-	-	-	-	-	-	1,481	197.0	1,102	636.4	5.8	29.2	-	-
2042	-	-	-	-	-	-	1,636	217.6	1,220	704.6	8.3	41.5	-	-
2043	-	-	-	-	-	-	1,561	207.6	1,314	759.2	10.8	53.8	-	-
2044	-	-	-	-	-	-	-	-	1,393	804.6	13.3	66.7	0.01	23.4

Annex 10.8

High Demand Case – Plant Schedule

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS	
2025	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage**	200 MW **50 MW** **10 MW** 10 MW 10 MW **5 MW/10 MWh**	**Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2026	Distribution Connected Embedded Solar **Grid Connected Solar** **Wind** Mini Hydro Biomass **Battery Energy Storage (Western Region)**	200 MW **220 MW** **90 MW** 10 MW 15 MW **100 MW/ 100 MWh**	**Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Gas Turbine (GT7)* *Extensions of plants to be retired* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	**235 MW** *(115) MW* *68 MW* *72 MW* *62 MW*
2027	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	200 MW 250 MW 260 MW 10 MW 20 MW	**Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
2028	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Southern Region)	200 MW 300 MW 200 MW 20 MW 20 MW 100 MW/ 400 MWh	**IC Engine Power Plant - Natural Gas**	**200 MW**
2029	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	200 MW 300 MW 200 MW 20 MW 20 MW 100 MW/ 400 MWh		
2030	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage (Western Region)	200 MW 300 MW 200 MW 20 MW 20 MW 50 MW/ 50 MWh	**Gas Turbine – Kelanitissa**	**130 MW**
2031	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	200 MW 200 MW 150 MW 20 MW 20 MW 200 MW/800 MWh	Gas Turbine - Natural Gas *Retirements of* *Sapugaskanda Station A* *Sapugaskanda Station B* *Barge Mounted Plant*	100 MW *(68) MW* *(72) MW* *(62) MW*
2032	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	200 MW 200 MW 150 MW 20 MW 20 MW 200 MW/800 MWh	Gas Turbine - Natural Gas	100 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS	
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	200 MW 200 MW 100 MW 20 MW 20 MW 100 MW/ 400 MWh	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	100 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pump Storage Hydropower (Maha)	150 MW 200 MW 100 MW 20 MW 20 MW 600 MW		
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 100 MW 10 MW 10 MW	Gas Turbine – Natural Gas & Hydrogen Blend *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage	150 MW 250 MW 100 MW 10 MW 10 MW 100 MW/ 400 MWh	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 250 MW 100 MW 10 MW 10 MW	HVDC Interconnection	500 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 300 MW 100 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 350 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 350 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro Battery Energy Storage	150 MW 380 MW 10 MW 50 MW/200 MWh	Gas Turbine - Natural Gas & Hydrogen Blend *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	2x300 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	150 MW 380 MW 500 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind-Offshore Mini Hydro	150 MW 380 MW 500 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Mini Hydro	150 MW 380 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Nuclear Power Plant *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	300 MW 600 MW *(300) MW* *(300) MW*

Annex 10.9

Low Demand Case – Plant Schedule

<table>
<tr><th>YEAR</th><th>RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE
CAPACITY ADDITIONS AND RETIREMENTS</th><th></th><th>THERMAL & INTERCONNECTION
CAPACITY ADDITIONS AND RETIREMENTS</th><th></th></tr>
<tr><td>2025</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage</td><td>150 MW
50 MW
10 MW
10 MW
10 MW
5 MW/10 MWh</td><td>Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)</td><td>115 MW</td></tr>
<tr><td>2026</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage (Western Region)</td><td>150 MW
220 MW
90 MW
10 MW
15 MW
100 MW/ 100 MWh</td><td>Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)

Retirement of
Gas Turbine (GT7)

Extensions of plants to be retired
Sapugaskanda Station A
Sapugaskanda Station B
Barge Mounted Plant</td><td>235 MW

(115) MW

68 MW
72 MW
62 MW</td></tr>
<tr><td>2027</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass</td><td>150 MW
250 MW
260 MW
10 MW
20 MW</td><td>Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)</td><td>115 MW</td></tr>
<tr><td>2028</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage (Southern Region)</td><td>150 MW
250 MW
100 MW
20 MW
20 MW
100 MW/ 400MWh</td><td>IC Engine Power Plant - Natural Gas</td><td>200 MW</td></tr>
<tr><td>2029</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage</td><td>150 MW
250 MW
100 MW
20 MW
20 MW
100 MW/ 400MWh</td><td></td><td></td></tr>
<tr><td>2030</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage (Western Region)</td><td>150 MW
250 MW
100 MW
20 MW
20 MW
50 MW/ 50 MWh</td><td>Gas Turbine – Kelanitissa</td><td>130 MW</td></tr>
<tr><td>2031</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage</td><td>150 MW
200 MW
100 MW
20 MW
20 MW
100 MW/400 MWh</td><td>Retirements of
Sapugaskanda Station A
Sapugaskanda Station B
Barge Mounted Plant</td><td>
(68) MW
(72) MW
(62) MW</td></tr>
<tr><td>2032</td><td>Distribution Connected Embedded Solar
Grid Connected Solar
Wind
Mini Hydro
Biomass
Battery Energy Storage</td><td>150 MW
200 MW
100 MW
20 MW
20 MW
100 MW/400 MWh</td><td>Gas Turbine - Natural Gas</td><td>100 MW</td></tr>
</table>

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS		THERMAL & INTERCONNECTION CAPACITY ADDITIONS AND RETIREMENTS	
2033	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 80 MW 20 MW 20 MW	Gas Turbine - Natural Gas *Retirements of* *Combined Cycle Power Plant (KPS)* *Combined Cycle Power Plant (KPS-2)* *Uthuru Janani Power Plant*	100 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Battery Energy Storage Pump Storage Hydropower (Maha)	150 MW 200 MW 80 MW 20 MW 20 MW 100 MW/ 400MWh 400 MW		
2035	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass Pump Storage Hydropower (Maha)	150 MW 200 MW 80 MW 10 MW 10 MW 200 MW	Gas Turbine – Natural Gas & Hydrogen Blend *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 80 MW 10 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Biomass	150 MW 200 MW 80 MW 10 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 80 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro Battery Energy Storage	150 MW 200 MW 80 MW 10 MW 100 MW/ 400MWh	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2040	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 80 MW 10 MW	HVDC Interconnection	500 MW
2041	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 80 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	300 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 200 MW 80 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend	200 MW
2043	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 300 MW 50 MW 10 MW	IC Engine Power Plant – Natural Gas & Hydrogen Blend	200 MW
2044	Distribution Connected Embedded Solar Grid Connected Solar Wind Mini Hydro	150 MW 300 MW 50 MW 10 MW	Gas Turbine - Natural Gas & Hydrogen Blend Nuclear Power Plant *Retirements of* *Lakvijaya Coal Power Plant Unit 2* *Lakvijaya Coal Power Plant Unit 3*	200 MW 600 MW *(300) MW* *(300) MW*

Annex 12.1
Investment Plan for Thermal & Interconnection Projects (Base Case) 2025-2044

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2025 L.C	2025 F.C	2026 L.C	2026 F.C	2027 L.C	2027 F.C	2028 L.C	2028 F.C	2029 L.C	2029 F.C	2030 L.C	2030 F.C	2031 L.C	2031 F.C	2032 L.C	2032 F.C	2033 L.C	2033 F.C	2034 L.C	2034 F.C	Total L.C	Total F.C	Grand Total
2025- 115 MW Steam Turbine of Sobadhanavi Natural Gas Combined Cycle Plant (Kerawalapitiya)																							
Base Cost	73.1	292.3																			**73.1**	**292.3**	**365.4**
Contingencies	7.3	29.2																			**7.3**	**29.2**	**36.5**
Port Handling & other charges (5%)		1.6																			**0.0**	**1.6**	**1.6**
Total	80.4	323.1																			**80.4**	**323.1**	**403.5**
2026 - 235 MW Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)																							
Base Cost			8.8	35.1																	**8.8**	**35.1**	**43.9**
Contingencies			0.9	3.5																	**0.9**	**3.5**	**4.4**
Port Handling & other charges (5%)				0.2																	**0.0**	**0.2**	**0.2**
Total			9.7	38.8																	**9.7**	**38.8**	**48.5**
2027 - 115 MW Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)																							
Base Cost					73.1	292.3															**73.1**	**292.3**	**365.4**
Contingencies					7.3	29.2															**7.3**	**29.2**	**36.5**
Port Handling & other charges (5%)						1.6															**0.0**	**1.6**	**1.6**
Total					80.4	323.1															**80.4**	**323.1**	**403.5**
2028 - 200 MW SIC Engine Power Plant - Natural Gas																							
Base Cost			4.4	17.5	39.3	157.2															**43.7**	**174.7**	**218.4**
Contingencies			0.4	1.8	3.9	15.7															**4.4**	**17.5**	**21.8**
Port Handling & other charges (5%)				0.1		0.9															**0.0**	**1.0**	**1.0**
Total			4.8	19.4	43.2	173.8															**48.1**	**193.2**	**241.2**
2030 - 130 MW Gas Turbine – Kelanitissa																							
Base Cost							1.6	6.5	14.5	58.1											**16.1**	**64.6**	**80.7**
Contingencies							0.2	0.6	1.5	5.8											**1.6**	**6.5**	**8.1**
Port Handling & other charges (5%)								0.0		0.3											**0.0**	**0.4**	**0.4**
Total							1.8	7.2	16.0	64.2											**17.8**	**71.4**	**89.2**
2031- 100 MW Gas Turbine - Natural Gas																							
Base Cost									1.2	4.8	10.7	42.9									**11.9**	**47.7**	**59.6**
Contingencies									0.1	0.5	1.1	4.3									**1.2**	**4.8**	**6.0**
Port Handling & other charges (5%)										0.0		0.2									**0.0**	**0.3**	**0.3**
Total									1.3	5.3	11.8	47.4									**13.1**	**52.7**	**65.8**
2033- 100 MW Gas Turbine - Natural Gas																							
Base Cost													1.2	4.8	10.7	42.9					**11.9**	**47.7**	**59.6**
Contingencies													0.1	0.5	1.1	4.3					**1.2**	**4.8**	**6.0**
Port Handling & other charges (5%)														0.0		0.2					**0.0**	**0.3**	**0.3**
Total													1.3	5.3	11.8	47.4					**13.1**	**52.7**	**65.8**
Annual Total	**80.4**	**323.1**	**14.5**	**58.2**	**123.6**	**496.9**	**1.8**	**7.2**	**17.3**	**69.5**	**11.8**	**47.4**	**1.3**	**5.3**	**11.8**	**47.4**							

Continued in the next page

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2033		2034		2035		2036		2037		2038		2039		**Total**		**Grand Total**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	
2035 - 300 MW Gas Turbine – Natural Gas & Hydrogen Blend																	
Base Cost	2.9	11.5	25.9	103.4											**28.7**	**115.0**	**143.7**
Contingencies	0.3	1.2	2.6	10.3											**2.9**	**11.5**	**14.4**
Port Handling & other charges (5%)		0.1		0.6											**0.0**	**0.6**	**0.6**
Total	3.2	12.8	28.4	114.3											**31.6**	**127.1**	**158.7**
2036 - 300 MW Gas Turbine – Natural Gas & Hydrogen Blend																	
Base Cost			2.9	11.5	25.9	103.4									**28.7**	**115.0**	**143.7**
Contingencies			0.3	1.2	2.6	10.3									**2.9**	**11.5**	**14.4**
Port Handling & other charges (5%)				0.1		0.6									**0.0**	**0.6**	**0.6**
Total			3.2	12.8	28.4	114.3									**31.6**	**127.1**	**158.7**
2037- 200 MW Gas Turbine – Natural Gas & Hydrogen Blend																	
Base Cost					2.3	9.2	20.7	82.6							**23.0**	**91.9**	**114.8**
Contingencies					0.2	0.9	2.1	8.3							**2.3**	**9.2**	**11.5**
Port Handling & other charges (5%)						0.1		0.5							**0.0**	**0.5**	**0.5**
Total					2.5	10.2	22.7	91.4							**25.3**	**101.6**	**126.8**
2038 - 200 MW IC Engine Power Plant - Natural Gas & Hydrogen Blend																	
Base Cost							4.4	17.5	39.3	157.1					**43.7**	**174.6**	**218.3**
Contingencies							0.4	1.8	3.9	15.7					**4.4**	**17.5**	**21.8**
Port Handling & other charges (5%)								0.1		0.9					**0.0**	**1.0**	**1.0**
Total							4.8	19.4	43.2	173.7					**48.0**	**193.1**	**241.1**
2039 - 500 MW HVDC Interconnection																	
Base Cost			12.3	49.0	36.8	147.0	83.3	333.2	85.8	343.0	27.0	107.8			**245.0**	**980.0**	**1225.0**
Contingencies			1.2	4.9	3.7	14.7	8.3	33.3	8.6	34.3	2.7	10.8			**24.5**	**98.0**	**122.5**
Port Handling & other charges (5%)				0.3		0.8		1.8		1.9		0.6			**0.0**	**5.4**	**5.4**
Total			13.5	54.2	40.4	162.5	91.6	368.4	94.3	379.2	29.6	119.2			**269.5**	**1083.4**	**1352.9**
2040 - 200 MW Gas Turbine - Natural Gas & Hydrogen Blend																	
Base Cost											2.3	9.2	20.7	82.6	**23.0**	**91.9**	**114.8**
Contingencies											0.2	0.9	2.1	8.3	**2.3**	**9.2**	**11.5**
Port Handling & other charges (5%)												0.1		0.5	**0.0**	**0.5**	**0.5**
Total											2.5	10.2	22.7	91.4	**25.3**	**101.6**	**126.8**
Annual Total	**88.7**	**356.5**	**45.1**	**181.3**	**71.4**	**287.1**	**119.2**	**479.1**	**137.5**	**552.9**	**32.2**	**129.4**					

Continued in the next page

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2039		2040		2041		2042		2043		2044		**Total**		**Grand Total**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	
2041 - 200 MW Gas Turbine - Natural Gas & Hydrogen Blend															
Base Cost	2.3	9.2	20.7	82.6									**23.0**	**91.9**	**114.8**
Contingencies	0.2	0.9	2.1	8.3									**2.3**	**9.2**	**11.5**
Port Handling & other charges (5%)		0.1		0.5									**0.0**	**0.5**	**0.5**
Total	2.5	10.2	22.7	91.4									**25.3**	**101.6**	**126.8**
2041 - 300 MWGas Turbine - Natural Gas & Hydrogen Blend															
Base Cost	2.9	11.5	25.9	103.4									**28.7**	**115.0**	**143.7**
Contingencies	0.3	1.2	2.6	10.3									**2.9**	**11.5**	**14.4**
Port Handling & other charges (5%)		0.1		0.6									**0.0**	**0.6**	**0.6**
Total	3.2	12.8	28.4	114.3									**31.6**	**127.1**	**158.7**
2042 - 300 MW Gas Turbine - Natural Gas & Hydrogen Blend															
Base Cost			2.9	11.5	25.9	103.4							**28.7**	**115.0**	**143.7**
Contingencies			0.3	1.2	2.6	10.3							**2.9**	**11.5**	**14.4**
Port Handling & other charges (5%)				0.1		0.6							**0.0**	**0.6**	**0.6**
Total			3.2	12.8	28.4	114.3							**31.6**	**127.1**	**158.7**
2043 - 200 MW IC Engine Power Plant – Natural Gas & Hydrogen Blend															
Base Cost					4.4	17.5	39.3	157.1					**43.7**	**174.6**	**218.3**
Contingencies					0.4	1.8	3.9	15.7					**4.4**	**17.5**	**21.8**
Port Handling & other charges (5%)						0.1		0.9					**0.0**	**1.0**	**1.0**
Total					4.8	19.4	43.2	173.7					**48.0**	**193.1**	**241.1**
2044 - 200 MW Gas Turbine - Natural Gas & Hydrogen Blend															
Base Cost							2.3	9.2	20.7	82.6			**23.0**	**91.9**	**114.8**
Contingencies							0.2	0.9	2.1	8.3			**2.3**	**9.2**	**11.5**
Port Handling & other charges (5%)								0.1		0.5			**0.0**	**0.5**	**0.5**
Total							2.5	10.2	22.7	91.4			**25.3**	**101.6**	**126.8**
2044 - 600 MW Nuclear Power Plant															
Base Cost	34.9	139.5	104.6	418.4	237.1	948.3	244.1	976.2	76.7	306.8			**697.3**	**2789.1**	**3486.4**
Contingencies	3.5	13.9	10.5	41.8	23.7	94.8	24.4	97.6	7.7	30.7			**69.7**	**278.9**	**348.6**
Port Handling & other charges (5%)		0.8		2.3		5.2		5.4		1.7			**0.0**	**15.3**	**15.3**
Total	38.4	154.2	115.1	462.5	260.8	1048.4	268.5	1079.2	84.4	339.2			**767.0**	**3083.4**	**3850.4**
Annual Total	**66.8**	**268.5**	**169.4**	**681.0**	**294.1**	**1182.1**	**314.2**	**1263.1**	**107.1**	**430.5**					

Annex 12.2

Investment Plan for Wind, Solar and Storage Development (Base Case), 2025-2044

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2024		2025		2026		2027		2028		2029		2030		2031		Total		Grand Total
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	
2025 - 150 MW Distribution Connected Embedded Solar																			
Base Cost			30.7	122.9													**30.7**	**122.9**	**153.6**
Contingencies			3.1	12.3													**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)				0.7													**0.0**	**0.7**	**0.7**
Total			33.8	135.8													**33.8**	**135.8**	**169.6**
2025 - 50 MW Grid Connected Solar																			
Base Cost	9.0	36.2															**9.0**	**36.2**	**45.2**
Contingencies	0.9	3.6															**0.9**	**3.6**	**4.5**
Port Handling & other charges (5%)		0.2															**0.0**	**0.2**	**0.2**
Total	9.9	40.0															**9.9**	**40.0**	**49.9**
2025 -10 MW Wind																			
Base Cost			3.0	11.9													**3.0**	**11.9**	**14.8**
Contingencies			0.3	1.2													**0.3**	**1.2**	**1.5**
Port Handling & other charges (5%)				0.1													**0.0**	**0.1**	**0.1**
Total			3.3	13.1													**3.3**	**13.1**	**16.4**
2026 - 150 MW Distribution Connected Embedded Solar																			
Base Cost					30.7	122.9											**30.7**	**122.9**	**153.6**
Contingencies					3.1	12.3											**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)						0.7											**0.0**	**0.7**	**0.7**
Total					33.8	135.8											**33.8**	**135.8**	**169.6**
2026 - 220 MW Grid Connected Solar																			
Base Cost	1.8	7.3	38.0	151.8													**39.8**	**159.1**	**198.9**
Contingencies	0.2	0.7	3.8	15.2													**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)		0.0		0.8													**0.0**	**0.9**	**0.9**
Total	2.0	8.0	41.8	167.9													**43.8**	**175.9**	**219.6**
2026 -90 MW Wind																			
Base Cost	1.8	7.1	16.0	64.0	8.9	35.6											**26.7**	**106.7**	**133.4**
Contingencies	0.2	0.7	1.6	6.4	0.9	3.6											**2.7**	**10.7**	**13.3**
Port Handling & other charges (5%)		0.0		0.4		0.2											**0.0**	**0.6**	**0.6**
Total	2.0	7.9	17.6	70.7	9.8	39.3											**29.3**	**118.0**	**147.3**
2026 - 100 MW/ 100 MWh Battery Energy Storage (Western Region)																			
Base Cost			6.0	24.0													**6.0**	**24.0**	**30.0**
Contingencies			0.6	2.4													**0.6**	**2.4**	**3.0**
Port Handling & other charges (5%)				0.1													**0.0**	**0.1**	**0.1**
Total			6.6	26.5													**6.6**	**26.5**	**33.1**
2027 - 150 MW Distribution Connected Embedded Solar																			
Base Cost							30.7	122.9									**30.7**	**122.9**	**153.6**
Contingencies							3.1	12.3									**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)								0.7									**0.0**	**0.7**	**0.7**
Total							33.8	135.8									**33.8**	**135.8**	**169.6**
Annual Total	**13.9**	**55.9**	**103.0**	**414.1**	**43.6**	**175.2**	**33.8**	**135.8**											

Continued in the next page

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2025		2026		2027		2028		2029		2030		2031		Total		Grand Total
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	
2027 - 250 MW Grid Connected Solar																	
Base Cost	4.5	18.2	40.7	162.6											**45.2**	**180.8**	**226.0**
Contingencies	0.5	1.8	4.1	16.3											**4.5**	**18.1**	**22.6**
Port Handling & other charges (5%)		0.1		0.9											**0.0**	**1.0**	**1.0**
Total	5.0	20.1	44.7	179.8											**49.7**	**199.9**	**249.6**
2027 -260 MW Wind																	
Base Cost	7.7	30.9	69.3	277.3											**77.1**	**308.3**	**385.3**
Contingencies	0.8	3.1	6.9	27.7											**0.0**	**1.7**	**1.7**
Port Handling & other charges (5%)		0.2		1.5											**84.8**	**340.8**	**425.5**
Total	8.5	34.2	76.3	306.6											**0.0**	**0.0**	**0.0**
2028 - 150 MW Distribution Connected Embedded Solar																	
Base Cost							30.7	122.9							**30.7**	**122.9**	**153.6**
Contingencies							3.1	12.3							**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)								0.7							**0.0**	**0.7**	**0.7**
Total							33.8	135.8							**33.8**	**135.8**	**169.6**
2028 - 300 MW Grid Connected Solar																	
Base Cost			5.4	21.8	48.8	195.2									**54.2**	**217.0**	**271.2**
Contingencies			0.5	2.2	4.9	19.5									**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)				0.1		1.1									**0.0**	**1.2**	**1.2**
Total			6.0	24.1	53.7	215.8									**59.7**	**239.8**	**299.5**
2028 -200 MW Wind																	
Base Cost			6.0	23.8	53.3	213.3									**59.3**	**237.1**	**296.4**
Contingencies			0.6	2.4	5.3	21.3									**5.9**	**23.7**	**29.6**
Port Handling & other charges (5%)				0.1		1.2									**0.0**	**1.3**	**1.3**
Total			6.5	26.3	58.7	235.8									**65.2**	**262.1**	**327.3**
2028 - 100 MW/ 400MWh Battery Energy Storage (Southern Region																	
Base Cost					31.0	124.1									**31.0**	**124.1**	**155.1**
Contingencies					3.1	12.4									**3.1**	**12.4**	**15.5**
Port Handling & other charges (5%)						0.7									**0.0**	**0.7**	**0.7**
Total					34.1	137.2									**34.1**	**137.2**	**171.3**
2029 - 150 MW Distribution Connected Embedded Solar																	
Base Cost									30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies									3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)										0.7					**0.0**	**0.7**	**0.7**
Total									33.8	135.8					**33.8**	**135.8**	**169.6**
2029 - 300 MW Grid Connected Solar																	
Base Cost					5.4	21.8	48.8	195.2							**54.2**	**217.0**	**271.2**
Contingencies					0.5	2.2	4.9	19.5							**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)						0.1		1.1							**0.0**	**1.2**	**1.2**
Total					6.0	24.1	53.7	215.8							**59.7**	**239.8**	**299.5**
Annual Total	**13.5**	**54.3**	**133.5**	**536.8**	**152.4**	**612.8**	**87.5**	**351.6**	**33.8**	**135.8**							

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2027		2028		2029		2030		2031		2032		2033	2034	**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C			**L.C**	**F.C**	**Total**
2029 -150 MW Wind																	
Base Cost	4.5	17.9	40.0	160.0											**44.5**	**177.8**	**222.3**
Contingencies	0.4	1.8	4.0	16.0											**4.4**	**17.8**	**22.2**
Port Handling & other charges (5%)		0.1		0.9											**0.0**	**1.0**	**1.0**
Total	4.9	19.7	44.0	176.9											**48.9**	**196.6**	**245.5**
2029 - 100 MW/ 400MWh Battery Energy Storage																	
Base Cost			31.0	124.1											**31.0**	**124.1**	**155.1**
Contingencies			3.1	12.4											**3.1**	**12.4**	**15.5**
Port Handling & other charges (5%)				0.7											**0.0**	**0.7**	**0.7**
Total			34.1	137.2											**34.1**	**137.2**	**171.3**
2030 - 150 MW Distribution Connected Embedded Solar																	
Base Cost							30.7	122.9							**30.7**	**122.9**	**153.6**
Contingencies							3.1	12.3							**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)								0.7							**0.0**	**0.7**	**0.7**
Total							33.8	135.8							**33.8**	**135.8**	**169.6**
2030 - 300 MW Grid Connected Solar																	
Base Cost			5.4	21.8	48.8	195.2									**54.2**	**217.0**	**271.2**
Contingencies			0.5	2.2	4.9	19.5									**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)				0.1		1.1									**0.0**	**1.2**	**1.2**
Total			6.0	24.1	53.7	215.8									**59.7**	**239.8**	**299.5**
2030 -150 MW Wind																	
Base Cost			4.5	17.9	40.0	160.0									**44.5**	**177.8**	**222.3**
Contingencies			0.4	1.8	4.0	16.0									**4.4**	**17.8**	**22.2**
Port Handling & other charges (5%)				0.1		0.9									**0.0**	**1.0**	**1.0**
Total			4.9	19.7	44.0	176.9									**48.9**	**196.6**	**245.5**
2030 - 50 MW/ 50MWh Battery Energy Storage																	
Base Cost					6.0	24.0									**6.0**	**24.0**	**30.0**
Contingencies					0.6	2.4									**0.6**	**2.4**	**3.0**
Port Handling & other charges (5%)						0.1									**0.0**	**0.1**	**0.1**
Total					6.6	26.5									**6.6**	**26.5**	**33.1**
2031 - 150 MW Distribution Connected Embedded Solar																	
Base Cost									30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies									3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)										0.7					**0.0**	**0.7**	**0.7**
Total									33.8	135.8					**33.8**	**135.8**	**169.6**
2031 - 200 MW Grid Connected Solar																	
Base Cost					3.6	14.5	32.5	130.1							**36.2**	**144.6**	**180.8**
Contingencies					0.4	1.5	3.3	13.0							**3.6**	**14.5**	**18.1**
Port Handling & other charges (5%)						0.1		0.7							**0.0**	**0.8**	**0.8**
Total					4.0	16.1	35.8	143.8							**39.8**	**159.9**	**199.7**
Annual Total	**4.9**	**19.7**	**89.0**	**357.9**	**108.3**	**435.2**	**69.6**	**279.7**	**33.8**	**135.8**							

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2029		2030		2031		2032		2033		2034		2035	2036	Total		Grand Total
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C			L.C	F.C	
2031 -100 MW Wind																	
Base Cost	3.0	11.9	26.7	106.7											**29.6**	**118.6**	**148.2**
Contingencies	0.3	1.2	2.7	10.7											**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)		0.1		0.6											**0.0**	**0.7**	**0.7**
Total	3.3	13.2	29.3	117.9											**32.6**	**131.1**	**163.7**
2031 - 100 MW/ 400MWh Battery Energy Storage																	
Base Cost			31.0	124.1											**31.0**	**124.1**	**155.1**
Contingencies			3.1	12.4											**3.1**	**12.4**	**15.5**
Port Handling & other charges (5%)				0.7											**0.0**	**0.7**	**0.7**
Total			34.1	137.2											**34.1**	**137.2**	**171.3**
2032 - 150 MW Distribution Connected Embedded Solar																	
Base Cost							30.7	122.9							**30.7**	**122.9**	**153.6**
Contingencies							3.1	12.3							**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)								0.7							**0.0**	**0.7**	**0.7**
Total							33.8	135.8							**33.8**	**135.8**	**169.6**
2032 - 200 MW Grid Connected Solar																	
Base Cost			3.6	14.5	32.5	130.1									**36.2**	**144.6**	**180.8**
Contingencies			0.4	1.5	3.3	13.0									**3.6**	**14.5**	**18.1**
Port Handling & other charges (5%)				0.1		0.7									**0.0**	**0.8**	**0.8**
Total			4.0	16.1	35.8	143.8									**39.8**	**159.9**	**199.7**
2032 -100 MW Wind																	
Base Cost			3.0	11.9	26.7	106.7									**29.6**	**118.6**	**148.2**
Contingencies			0.3	1.2	2.7	10.7									**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)				0.1		0.6									**0.0**	**0.7**	**0.7**
Total			3.3	13.2	29.3	117.9									**32.6**	**131.1**	**163.7**
2032 - 200 MW/ 800MWh Battery Energy Storage																	
Base Cost					62.0	248.2									**62.0**	**248.2**	**310.2**
Contingencies					6.2	24.8									**6.2**	**24.8**	**31.0**
Port Handling & other charges (5%)						1.4									**0.0**	**1.4**	**1.4**
Total					68.2	274.3									**68.2**	**274.3**	**342.6**
2033 - 150 MW Distribution Connected Embedded Solar																	
Base Cost									30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies									3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)										0.7					**0.0**	**0.7**	**0.7**
Total									33.8	135.8					**33.8**	**135.8**	**169.6**
2033 - 200 MW Grid Connected Solar																	
Base Cost					3.6	14.5	32.5	130.1							**36.2**	**144.6**	**180.8**
Contingencies					0.4	1.5	3.3	13.0							**3.6**	**14.5**	**18.1**
Port Handling & other charges (5%)						0.1		0.7							**0.0**	**0.8**	**0.8**
Total					4.0	16.1	35.8	143.8							**39.8**	**159.9**	**199.7**
Annual Total	**3.3**	**13.2**	**70.7**	**284.3**	**137.4**	**552.1**	**69.6**	**279.7**	**33.8**	**135.8**							

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2029		2030		2031		2032		2033		2034		2035		2036		Total		Grand Total
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	
2033 -100 MW Wind																			
Base Cost					3.0	11.9	26.7	106.7									**29.6**	**118.6**	**148.2**
Contingencies					0.3	1.2	2.7	10.7									**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)						0.1		0.6									**0.0**	**0.7**	**0.7**
Total					3.3	13.2	29.3	117.9									**32.6**	**131.1**	**163.7**
2033 - 100 MW/ 400MWh Battery Energy Storage																			
Base Cost							31.0	124.1									**31.0**	**124.1**	**155.1**
Contingencies							3.1	12.4									**3.1**	**12.4**	**15.5**
Port Handling & other charges (5%)								0.7									**0.0**	**0.7**	**0.7**
Total							34.1	137.2									**34.1**	**137.2**	**171.3**
2034 - 150 MW Distribution Connected Embedded Solar																			
Base Cost											30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies											3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)												0.7					**0.0**	**0.7**	**0.7**
Total											33.8	135.8					**33.8**	**135.8**	**169.6**
2034 - 200 MW Grid Connected Solar																			
Base Cost							3.6	14.5	32.5	130.1							**36.2**	**144.6**	**180.8**
Contingencies							0.4	1.5	3.3	13.0							**3.6**	**14.5**	**18.1**
Port Handling & other charges (5%)								0.1		0.7							**0.0**	**0.8**	**0.8**
Total							4.0	16.1	35.8	143.8							**39.8**	**159.9**	**199.7**
2034 -100 MW Wind																			
Base Cost							3.0	11.9	26.7	106.7							**29.6**	**118.6**	**148.2**
Contingencies							0.3	1.2	2.7	10.7							**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)								0.1		0.6							**0.0**	**0.7**	**0.7**
Total							3.3	13.2	29.3	117.9							**32.6**	**131.1**	**163.7**
2034 - 600 MW Pump Storage Power Plant (Maha)																			
Base Cost	6.1	24.4	12.2	48.9	30.5	122.2	54.8	219.2	77.7	310.9							**181.4**	**725.6**	**907.0**
Contingencies	0.6	2.4	1.2	4.9	3.1	12.2	5.5	21.9	7.8	31.1							**18.1**	**72.6**	**90.7**
Port Handling & other charges (5%)		0.1		0.3		0.7		1.2		1.7							**0.0**	**4.0**	**4.0**
Total	6.7	27.0	13.4	54.0	33.6	135.0	60.3	242.4	85.5	343.7							**199.5**	**802.2**	**1001.7**
2035 - 150 MW Distribution Connected Embedded Solar																			
Base Cost													30.7	122.9			**30.7**	**122.9**	**153.6**
Contingencies													3.1	12.3			**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)														0.7			**0.0**	**0.7**	**0.7**
Total													33.8	135.8			**33.8**	**135.8**	**169.6**
2035 - 200 MW Grid Connected Solar																			
Base Cost									3.6	14.5	32.5	130.1					**36.2**	**144.6**	**180.8**
Contingencies									0.4	1.5	3.3	13.0					**3.6**	**14.5**	**18.1**
Port Handling & other charges (5%)									0.0		0.2						**0.2**	**0.0**	**0.2**
Total									4.0	16.0	36.0	143.1					**40.0**	**159.1**	**199.1**
Annual Total	**6.7**	**27.0**	**13.4**	**54.0**	**36.9**	**148.2**	**131.0**	**526.7**	**154.6**	**621.4**	**69.8**	**279.0**	**33.8**	**135.8**					

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2033		2034		2035		2036		2037		2038		2039	2040	**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C			**L.C**	**F.C**	**Total**
2035 -100 MW Wind																	
Base Cost	3.0	11.9	26.7	106.7											**29.6**	**118.6**	**148.2**
Contingencies	0.3	1.2	2.7	10.7											**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)	0.0		0.1												**0.2**	**0.0**	**0.2**
Total	3.3	13.1	29.5	117.3											**32.8**	**130.4**	**163.2**
2036 - 150 MW Distribution Connected Embedded Solar																	
Base Cost							30.7	122.9							**30.7**	**122.9**	**153.6**
Contingencies							3.1	12.3							**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)								0.7							**0.0**	**0.7**	**0.7**
Total							33.8	135.8							**33.8**	**135.8**	**169.6**
2036 - 250 MW Grid Connected Solar																	
Base Cost			4.5	18.2	40.7	162.6									**45.2**	**180.8**	**226.0**
Contingencies			0.5	1.8	4.1	16.3									**4.5**	**18.1**	**22.6**
Port Handling & other charges (5%)			0.0		0.2										**0.2**	**0.0**	**0.2**
Total			5.0	20.0	45.0	178.9									**50.0**	**198.9**	**248.8**
2036 -100 MW Wind																	
Base Cost			3.0	11.9	26.7	106.7									**29.6**	**118.6**	**148.2**
Contingencies			0.3	1.2	2.7	10.7									**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)			0.0		0.1										**0.2**	**0.0**	**0.2**
Total			3.3	13.1	29.5	117.3									**32.8**	**130.4**	**163.2**
2037 - 150 MW Distribution Connected Embedded Solar																	
Base Cost									30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies									3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)										0.7					**0.0**	**0.7**	**0.7**
Total									33.8	135.8					**33.8**	**135.8**	**169.6**
2037 - 250 MW Grid Connected Solar																	
Base Cost					4.5	18.2	40.7	162.6							**45.2**	**180.8**	**226.0**
Contingencies					0.5	1.8	4.1	16.3							**4.5**	**18.1**	**22.6**
Port Handling & other charges (5%)					0.0		0.2								**0.2**	**0.0**	**0.2**
Total					5.0	20.0	45.0	178.9							**50.0**	**198.9**	**248.8**
2037 -100 MW Wind																	
Base Cost					3.0	11.9	26.7	106.7							**29.6**	**118.6**	**148.2**
Contingencies					0.3	1.2	2.7	10.7							**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)					0.0		0.1								**0.2**	**0.0**	**0.2**
Total					3.3	13.1	29.5	117.3							**32.8**	**130.4**	**163.2**
2037 - 100 MW/ 400MWh Battery Energy Storage																	
Base Cost									31.0	124.1					**31.0**	**124.1**	**155.1**
Contingencies									3.1	12.4					**3.1**	**12.4**	**15.5**
Port Handling & other charges (5%)									0.2						**0.2**	**0.0**	**0.2**
Total									34.3	136.5					**34.3**	**136.5**	**170.8**
Annual Total	**3.3**	**13.1**	**37.8**	**150.4**	**82.7**	**329.3**	**108.2**	**432.1**	**68.1**	**272.3**							

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2036 L.C	2036 F.C	2037 L.C	2037 F.C	2038 L.C	2038 F.C	2039 L.C	2039 F.C	2040 L.C	2040 F.C	2041 L.C	2041 F.C	2042	2043	Total L.C	Total F.C	Grand Total
2038 - 150 MW Distribution Connected Embedded Solar																	
Base Cost					30.7	122.9									**30.7**	**122.9**	**153.6**
Contingencies					3.1	12.3									**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)						0.7									**0.0**	**0.7**	**0.7**
Total					33.8	135.8									**33.8**	**135.8**	**169.6**
2038 - 250 MW Grid Connected Solar																	
Base Cost	4.5	18.2	40.7	162.6											**45.2**	**180.8**	**226.0**
Contingencies	0.5	1.8	4.1	16.3											**4.5**	**18.1**	**22.6**
Port Handling & other charges (5%)	0.0		0.2												**0.2**	**0.0**	**0.2**
Total	5.0	20.0	45.0	178.9											**50.0**	**198.9**	**248.8**
2038 -100 MW Wind																	
Base Cost	3.0	11.9	26.7	106.7											**29.6**	**118.6**	**148.2**
Contingencies	0.3	1.2	2.7	10.7											**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)	0.0		0.1												**0.2**	**0.0**	**0.2**
Total	3.3	13.1	29.5	117.3											**32.8**	**130.4**	**163.2**
2039 - 150 MW Distribution Connected Embedded Solar																	
Base Cost							30.7	122.9							**30.7**	**122.9**	**153.6**
Contingencies							3.1	12.3							**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)								0.7							**0.0**	**0.7**	**0.7**
Total							33.8	135.8							**33.8**	**135.8**	**169.6**
2039 - 250 MW Grid Connected Solar																	
Base Cost			4.5	18.2	40.7	162.6									**45.2**	**180.8**	**226.0**
Contingencies			0.5	1.8	4.1	16.3									**4.5**	**18.1**	**22.6**
Port Handling & other charges (5%)			0.0		0.2										**0.2**	**0.0**	**0.2**
Total			5.0	20.0	45.0	178.9									**50.0**	**198.9**	**248.8**
2039 -100 MW Wind																	
Base Cost			3.0	11.9	26.7	106.7									**29.6**	**118.6**	**148.2**
Contingencies			0.3	1.2	2.7	10.7									**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)			0.0		0.1										**0.2**	**0.0**	**0.2**
Total			3.3	13.1	29.5	117.3									**32.8**	**130.4**	**163.2**
2040 - 150 MW Distribution Connected Embedded Solar																	
Base Cost									30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies									3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)										0.7					**0.0**	**0.7**	**0.7**
Total									33.8	135.8					**33.8**	**135.8**	**169.6**
2040 - 250 MW Grid Connected Solar																	
Base Cost					4.5	18.2	40.7	162.6							**45.2**	**180.8**	**226.0**
Contingencies					0.5	1.8	4.1	16.3							**4.5**	**18.1**	**22.6**
Port Handling & other charges (5%)					0.0		0.2								**0.2**	**0.0**	**0.2**
Total					5.0	20.0	45.0	178.9							**50.0**	**198.9**	**248.8**
Annual Total	**8.3**	**33.1**	**82.7**	**329.3**	**113.2**	**452.0**	**78.7**	**314.8**	**33.8**	**135.8**							

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2036		2037		2038		2039		2040		2041		2042		2043		**Total**		**Grand Total**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	
2040 -100 MW Wind																			
Base Cost					3.0	11.9	26.7	106.7									**29.6**	**118.6**	**148.2**
Contingencies					0.3	1.2	2.7	10.7									**3.0**	**11.9**	**14.8**
Port Handling & other charges (5%)					0.0		0.1										**0.2**	**0.0**	**0.2**
Total					3.3	13.1	29.5	117.3									**32.8**	**130.4**	**163.2**
2041 - 150 MW Distribution Connected Embedded Solar																			
Base Cost											30.7	122.9					**30.7**	**122.9**	**153.6**
Contingencies											3.1	12.3					**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)												0.7					**0.0**	**0.7**	**0.7**
Total											33.8	135.8					**33.8**	**135.8**	**169.6**
2041 - 300 MW Grid Connected Solar																			
Base Cost							5.4	21.8	48.8	195.2							**54.2**	**217.0**	**271.2**
Contingencies							0.5	2.2	4.9	19.5							**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)							0.0		0.3								**0.3**	**0.0**	**0.3**
Total							6.0	24.0	53.9	214.7							**60.0**	**238.7**	**298.6**
2042 - 150 MW Distribution Connected Embedded Solar																			
Base Cost													30.7	122.9			**30.7**	**122.9**	**153.6**
Contingencies													3.1	12.3			**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)														0.7			**0.0**	**0.7**	**0.7**
Total													33.8	135.8			**33.8**	**135.8**	**169.6**
2042 - 300 MW Grid Connected Solar																			
Base Cost									5.4	21.8	48.8	195.2					**54.2**	**217.0**	**271.2**
Contingencies									0.5	2.2	4.9	19.5					**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)									0.0		0.3						**0.3**	**0.0**	**0.3**
Total									6.0	24.0	53.9	214.7					**60.0**	**238.7**	**298.6**
2043 - 150 MW Distribution Connected Embedded Solar																			
Base Cost															30.7	122.9	**30.7**	**122.9**	**153.6**
Contingencies															3.1	12.3	**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)																0.7	**0.0**	**0.7**	**0.7**
Total															33.8	135.8	**33.8**	**135.8**	**169.6**
2043 - 300 MW Grid Connected Solar																			
Base Cost											5.4	21.8	48.8	195.2			**54.2**	**217.0**	**271.2**
Contingencies											0.5	2.2	4.9	19.5			**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)											0.0		0.3				**0.3**	**0.0**	**0.3**
Total											6.0	24.0	53.9	214.7			**60.0**	**238.7**	**298.6**
2043 - 500 MW Wind-Offshore																			
Base Cost									42.0	168.0	243.7	974.6	134.4	537.7			**420.1**	**1680.4**	**2100.5**
Contingencies									4.2	16.8	24.4	97.5	13.4	53.8			**42.0**	**168.0**	**210.1**
Port Handling & other charges (5%)									0.2		1.3		0.7				**2.3**	**0.0**	**2.3**
Total									46.4	184.8	269.4	1072.1	148.6	591.5			**464.4**	**1848.4**	**2312.9**
Annual Total	**49.7**	**197.9**	**82.7**	**329.3**	**79.4**	**316.2**	**78.7**	**314.8**	**33.8**	**135.8**									

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

(Costs in million USD, Exch. Rate: 326.7 LKR/US$)

YEAR & PLANT	2040		2041		2042		2043		2044				Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2044 - 150 MW Distribution Connected Embedded Solar													
Base Cost									30.7	122.9	**30.7**	**122.9**	**153.6**
Contingencies									3.1	12.3	**3.1**	**12.3**	**15.4**
Port Handling & other charges (5%)										0.7	**0.0**	**0.7**	**0.7**
Total									33.8	135.8	**33.8**	**135.8**	**169.6**
2044 - 300 MW Grid Connected Solar													
Base Cost					5.4	21.8	48.8	195.2			**54.2**	**217.0**	**271.2**
Contingencies					0.5	2.2	4.9	19.5			**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)					0.0		0.3				**0.3**	**0.0**	**0.3**
Total					6.0	24.0	53.9	214.7			**60.0**	**238.7**	**298.6**
2044 - 50 MW/ 200MWh Battery Energy Storage													
Base Cost							15.5	62.0			**15.5**	**62.0**	**77.6**
Contingencies							1.6	6.2			**1.6**	**6.2**	**7.8**
Port Handling & other charges (5%)							0.1	0.3			**0.1**	**0.3**	**0.4**
Total							17.1	68.6			**17.1**	**68.6**	**85.7**
Annual Total	**0.0**	**0.0**	**0.0**	**0.0**	**6.0**	**24.0**	**71.1**	**283.3**	**33.8**	**135.8**			

Annex 13.1

Energy Deficit Risk

Case	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Dry Hydro Condition	2025	0.15%	0.06%	0.03%	0.01%	0.00%	0.06%	0.04%	0.05%	0.03%	0.03%	0.03%	0.14%
	2026	0.04%	0.03%	0.01%	0.01%	0.00%	0.00%	0.00%	0.02%	0.06%	0.08%	0.05%	0.10%
	2027	0.06%	0.06%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%
	2028	0.01%	0.01%	0.01%	0.00%	0.01%	0.01%	0.01%	0.01%	0.00%	0.02%	0.04%	0.02%
	2029	0.04%	0.01%	0.01%	0.00%	0.00%	0.03%	0.06%	0.00%	0.00%	0.03%	0.01%	0.02%
High Demand	2025	0.18%	0.09%	0.07%	0.06%	0.02%	0.09%	0.09%	0.06%	0.09%	0.10%	0.10%	0.11%
	2026	0.12%	0.08%	0.07%	0.03%	0.04%	0.05%	0.08%	0.09%	0.11%	0.13%	0.13%	0.12%
	2027	0.08%	0.03%	0.05%	0.03%	0.02%	0.01%	0.02%	0.01%	0.01%	0.05%	0.02%	0.03%
	2028	0.04%	0.03%	0.02%	0.01%	0.01%	0.01%	0.02%	0.01%	0.03%	0.04%	0.03%	0.03%
	2029	0.04%	0.02%	0.02%	0.01%	0.02%	0.03%	0.02%	0.01%	0.03%	0.04%	0.04%	0.04%
Long Outage of Major Plant	2025	0.09%	0.10%	0.06%	0.06%	0.05%	0.07%	0.09%	0.04%	0.10%	0.08%	0.11%	0.12%
	2026	0.09%	0.10%	0.06%	0.04%	0.05%	0.06%	0.07%	0.09%	0.11%	0.21%	0.10%	0.11%
	2027	0.09%	0.04%	0.03%	0.02%	0.01%	0.01%	0.02%	0.01%	0.07%	0.05%	0.04%	0.04%
	2028	0.04%	0.03%	0.03%	0.02%	0.01%	0.02%	0.02%	0.02%	0.03%	0.04%	0.03%	0.03%
	2029	0.05%	0.04%	0.02%	0.01%	0.01%	0.02%	0.03%	0.02%	0.03%	0.09%	0.03%	0.04%
Restricted Fuel Supply Case 1	2025	0.07%	6.61%	14.84%	6.94%	1.84%	2.97%	15.31%	1.66%	0.13%	2.42%	2.96%	1.22%
	2026	9.73%	17.45%	18.16%	16.70%	2.13%	0.66%	1.56%	1.44%	9.35%	3.65%	3.91%	0.97%
	2027	9.06%	15.87%	16.37%	4.07%	6.19%	1.11%	0.03%	1.32%	6.19%	5.09%	5.43%	2.69%
	2028	5.93%	12.53%	11.20%	4.28%	1.99%	1.56%	2.05%	0.28%	0.49%	10.98%	1.29%	1.60%
	2029	4.72%	14.76%	12.29%	9.70%	0.05%	0.09%	0.35%	2.83%	6.84%	2.67%	10.26%	10.00%
Restricted Fuel Supply Case 2	2025	2.81%	17.30%	27.26%	17.75%	9.28%	3.24%	16.79%	10.29%	4.42%	2.66%	3.56%	8.80%
	2026	21.96%	26.92%	29.44%	17.29%	8.48%	2.98%	8.84%	6.10%	9.38%	4.60%	4.26%	7.58%
	2027	20.28%	24.33%	26.61%	11.64%	6.67%	3.31%	2.17%	7.36%	6.34%	5.09%	5.83%	9.25%
	2028	12.61%	19.68%	20.29%	10.26%	2.31%	1.60%	2.19%	1.73%	3.50%	10.68%	4.48%	6.95%
	2029	12.42%	21.53%	19.84%	9.84%	1.39%	0.73%	1.34%	3.07%	6.70%	2.89%	17.25%	2.78%
Implementation Delay Case 8	2025	N/A	0.11%	0.06%	0.05%	0.02%	0.06%	0.07%	0.05%	0.10%	0.08%	0.11%	0.14%
	2026	0.09%	0.07%	0.06%	0.06%	0.05%	0.05%	0.06%	0.08%	0.16%	0.59%	0.12%	0.13%
	2027	0.11%	0.08%	0.05%	0.03%	0.02%	0.01%	0.02%	0.02%	0.04%	0.09%	0.03%	0.04%
	2028	0.03%	0.02%	0.01%	0.01%	0.01%	0.02%	0.02%	0.01%	0.02%	0.30%	0.03%	0.04%
	2029	0.05%	0.04%	0.01%	0.01%	0.01%	0.01%	0.02%	0.02%	0.03%	0.04%	0.03%	0.03%

Note: "Energy Deficit Risk Percentage" is indicated as a possibility of monthly energy deficit respective to the monthly energy demand.

Annex 15.1

Actual Generation Expansions and the Plans from 1993-2024

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)														
		1996-2010	1998-2012	1999-2013	2000-2014	2002-2016	2003-2017	2005-2019	2006-2020	2009-2022	2011-2025	2013-2032	2015-2034	2018-2037	2022-2041	2023-2042	2025-2044
2010	270-WC CCY	300-CO	105-GT	300-CO	300-CO	300-CO	-	300-CO 150-UPK	75-GT 2*105-GT	270-CCY	-	-	-	-	-	-	
2011	285-PUT	-	300-TRNC	-	300-TRNC	-	300-CO	300-CO	2*300-CO 150-UPK	285-PUT	315-PUT	-	-	-	-	-	
2012	150-UPK	-	210-GT	300-TRNC	105-GT	300-CO	300-CO	300-CO	300-CO	150-UPK	150-UPK	-	-	-	-	-	
2013	-	-	-	105-GT 10-DS	300-TRNC	300-TRNC	105-GT	300-CO	300-CO	2*285-PUT(ST2) 250-TPCL	-	-	-	-	-	-	
2014	2*285-PUT 20-Northern 24-CPE	_	_	_	210-GT	_	300-CO	300-CO	300-CO	250-TPCL	20-Northern 24-CPE 75-GT 2*315-PUT	20-Northern 24-CPE 300-PUT	-	-	-	-	
2015	60-Col(CEB)	_	_	_	_	300-TRNC	300-CO 210-GT	285-GT	300-CO	300-CO	2*35-GT	300-PUT 3*75-GT	60-Col(CEB)		-	-	
2016	_	_	_	_	_	175-GT	300-CO	300-CO	300-CO	_	35-BDL 120-Uma Oya	35-BDL 120-Uma Oya	-		-	-	
2017	100-ACE+ 20-ACE+	_	_	_		_	210-GT	300-CO	300-CO	300-CO	2*250-TPCL	105-GT	170-FO		-	-	
2018	_	_	_	_	_	_	_	300-CO 180-GT	300-CO	300-CO	49-GIN 250-TPCL	27-Moragolla 2*250-TPCL	35-BDL 120-Uma Oya 2*35-GT	320-FO	-	-	
2019	_	_	_	_	_	_	_	420-GT	300-CO	_	250-TPCL	2*300-CO	35-GT 300-LNG	300-CCY(NG) 120-Uma Oya	-	-	
2020	_	_	_	_	_	_	_	_	105-GT 300-CO	300-CO	_	_	15-THAL	35-BDL 15-THAL 35-GT	-	-	
2021	_	_	_	_	_	_	_	_	_	300-CO	2*300-CO	300-CO	250-TPCL**	300-CCY(NG)	-	-	
2022	35-Broadlands	_	_	_	_	_	_	_	_	300-CO	300-CO	300-CO 49-GIN	31-Moragolla 20-SEETHA 20-GIN 250-TPCL**	31-Moragolla 20-SEETHA 20-GIN	35-BDL 120-Uma Oya	120-Uma Oya	
2023	_	_	_	_	_	_	_	_	_	_	300-CO	2*300-CO	163-AES CCY(LNG) 300-ASC CO	163-AES CCY(NG) 300-ASC CO	130 GT	235-CCY (NG)	
2024	120-Uma Oya 212-Soba GT (Diesel)	_	_	_	_	_	_	_	_	_	_	_	300-ASC CO	300-ASC CO	31-Moragolla 350-CCY (NG)	31- Moragolla 130 GT 350 CCY (NG)	31- Moragolla
2025	_	_	_	_	_	_	_	_	_	_	2*300-CO	300-CO	200 PSPP	300-ASC CO 200 PSPP	350-CCY (NG) 300 Coal LVPS	115 CCY (NG)	115 CCY (NG)
2026	_	_	_	_	_	_	_	_	_	_	_	_	200 PSPP	200 PSPP	250 Gas Engine LNG	200 Gas Engine (NG)	235 GT (NG)
2027	_	_	_	_	_	_	_	_	_	_	_	300- CO	300- ASC CO	200 PSPP	400 CCY (NG)	100 GT (NG)	115 CCY (NG)
2028	_	_	_	_	_	_	_	_	_	_	_	300- CO	_	600 - ASC CO	300 Coal	_	200 Gas Engine(NG)
2029	_	_	_	_	_	_	_	_	_	_	_	_	300- ASC CO	_	_	_	
2030	_	_	_	_	_	_	_	_	_	_	_	300- CO	300- ASC CO	_	_	_	130 GT (NG)

Note: ORE Plants are not indicated ** Approval was not granted by PUCSL +PPA has extended and procurment of power plants by CEB is under consideration

KUK – Kukule hydro power station, BDL – Broadlands hydro power station, UPK – Upper Kotmale hydro power station, GIN – Gin ganga hydro power station, THAL - Thalpitigala, SEETHA - Seethawaka

ST – Steam plant, DS – Diesel plant, CPE-Chunnakum Power Extension, CCY – Combined cycle plant, CO – Coal fired steam plant, GT – Gas turbine, LKV – Lakdanavi power plant, Asia – Asia power plant, Col – Colombo power plant, ACE – ACE power plant,HLV-Heladanavi power station, TRNC-Trinco Coal Power Plant, Northern-Northern Power plant, PUT-Puttalam Coal Power Plant, TPCL-Trincomalee Power Company Coal Power Plant, FO-Furnace Oil power plant, NG - Natural Gas, ASC CO-Advanced Sub Critical Coal Power Plant, AES CCY(NG)-AES Kelanitissa Convertion to LNG, Col(CEB)-CEB Colombo Power Plant, PSPP - Pumped storage power plant, Soba- Sobadhanavi Power Plant

Annex 15.2

Actual ORE Generation Expansions and the Plans from 2015-2025

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)			
		2018-2037	2022-2041	2023-2042	2025-2044
2013	S-4 W-5 MH-37 B-0	-	-	-	
2014	S-10 W-50 MH-24 B-7	-	-	-	
2015	S-15 W-0 MH-19 B-0		-	-	
2016	S-36 W-0 MH-35 B-4		-	-	
2017	S-83 W-0 MH-12 B-2		-	-	
2018	S-74 W-0 MH-40 B-10	S-160 W-0 MH-15 B-5	-	-	
2019	S-117 W-0 MH-16 B-0	S-95 W-50 MH-15 B-5	-	-	
2020	S-75 W-51 MH-2 B-10	S-105 W- 220 MH-15 B-5	-	-	
2021	S-202 W-73 MH-0 B-0	S-55 W-75 MH-15 B-14	-	-	
2022	S - 176 W - 0 MH - 0 B- 0	S-6 W-50 MH-10 B-5	S-340 W-20 MH-15 B-14		
2023	S- 158 W- 15 MH- 5 B- 4	S-55 W-60 MH-10 B-5	S-260 W-35 MH-20 B-4	S-307 W-25 MH-20 B-20	
2024	–	S-55 W-45 MH-10 B-5	S-270 W-40 MH-10 B-5	S-483 W-60 MH-20 B-20	
2025	–	S-104 W-85 MH-0 B-5	S-260 W100 MH-10 B-5	S-505 W200 MH-25 B-20	S-200 W-10 MH-10 B-10
2026	–	S-55 W-0 MH-10 B-5	S-195 W100 MH-10 B-5	S-500 W290 MH-25 B-20	S-370 W-90 MH-10 B-15
2027	–	S-54 W-25 MH-10 B-5	S-160 W120 MH-10 B-5	S-500 W250 MH-25 B-20	S-400 W260 MH-10 B-20
2028	–	S-105 W-45 MH-10 B-5	S-170 W120 MH-10 B-5	S-520 W200 MH-25 B-20	S-450 W200 MH-20 B-20
2029	–	S-54 W-25 MH-10 B-5	S-160 W-100 MH-10 B-5	S-540 W250 MH-25 B-20	S-450 W150 MH-20 B-20
2030	–	S-55 W-70 MH-10 B-7	S-170 W-130 MH-10 B-5	S-450 W200 MH-10 B-20	S-450 W150 MH-20 B-20

Note: S - Solar, W - Wind, MH - Mini Hydro, B - Bio Mass

Annex 16
Supplementary Information and Clarifications Provided to PUCSL

(i) Clarifications via Letter Reference GP/CE/EXPAN/2023 dated 21st November 2024

1. Reason for using capital and O&M costs for candidate thermal and ORE technologies different to the input submitted to the Commission with the letter (Ref: GP/CE/EXPAN-2023) dated 17 November 2023. Provide the economic indicators/factors considered if these costs have been escalated.

According to the Grid Code all costs & prices used in planning studies shall reflect the economic conditions as on 1st January of the current year. For LTGEP 2025 2044 the current year is 2024 but the time of submitting input data the latest data available was for year 2021/2022. Hence it is required to escalate the costs to reflect 2024 (2023 end) values.

As already informed in the letter GP/CE/EXPAN-2023 dated 17 November 2023, the costs were escalated based on local & foreign economic indicators shown below.

Assumption: Local to foreign portion of the cost is 20%:80%

Indicator	Value
CCPI 2023	17.4
CCPI 2022	46.4
Exchange Rate 2023	326.74
Exchange Rate 2022	363.16
Exchange Rate 2021	201.4
GDP Deflator – Advanced Economies 2023	3.9
GDP Deflator – Advanced Economies 2022	5.4

2. Reason for using higher capital cost for Battery Energy Storage Systems (BESS) compared to the cost applied in the previous plan (LTGEP 2023-2042) despite the global downward trend in BESS prices.

In LTGEP 2023 2042 BESS costs were derived based on 2021 Annual Technology Baseline (ATB), National Renewable Energy Laboratory. For LTGEP 2025 2044 the source was changed to GenCost 2022-23, Final Report, Australia's National Science Agency, CSIRO, July 2023.

Following is the comparison of the capital cost of BESS in publications of GenCost 2022-23 and the parallel ATB report, 2023 ATB.

BESS Type	2023 ATB (US$/kW)	GenCost 2022-23 (US$/kW)
2 hr	1,060	875
4 hr	1,784	1,420
8 hr	3,232	2,523

It can be observed that 2023 ATB values for 4 hr BESS is 34% higher than the LTGEP 2023-2042 value of 1330 $/kW, which is a significant increase. Furthermore, ATB costs are approximately 21-28% higher than the respective GenCost costs. Hence, we have taken the GenCost 2022-23 data for LTGEP 2025-2044 which only indicates a 7% increase from the previous LTGEP value and escalated the value for year 2024.

Hence ,it is evident at the time of preparation of the plan, the available published sources had an increase in the capital cost of BESS systems. The same is reflected in LTGEP 2025-2044.

3. **Reason for the delay in commission the first Pumped Storage Power Plant from 2029 to 2034, as compared to the plant schedule of the LTGEP 2023-2042.**

The Detailed feasibility study of the most promising candidate site (Maha Oya Project) was concluded in year 2024. Given the time frame for next pre construction activities including funding and financing , environmental and other approvals, resettlement plans the project will have high lead time. Furthermore, the planned construction time period is 5 years. Considering the required pre construction and construction activities, the most optimistic earliest availability of the PSPP shall be beyond year 2032.

In addition, due to the substantial demand drop after the economic recession in recent years, there is a 4-year lag in demand compared to the previous LTGEP. Hence the renewable energy additions and their corresponding curtailments are reduced which results in PSPP requirement being less viable before 2034.

4. **Reason for exclusion of the Wewathenna Pumped Storage (2 x 350MW) from the base case which was included in the plant schedule of the LTGEP 2023-2042.**

In LTGEP 2023-2042, pumped storage power plant candidate details were based on data available from "Development Planning on Optimal Power Generation for Peak power Demand in Sri Lanka (2015)" & Project on Electricity Sector Master Plan Study (2018). However, to select the most promising site for first development, both sites were evaluated with detailed prefeasibility study in 2023 with ADB assistance. Subsequently, during the pre-feasibility study on pumped storage hydropower project (2023), Wewatenna potential was reduced from 1400 MW to 700 MW and considering the actual geological conditions at the project site. Hence the construction cost (USD/kW) had also increased, which resulted in lower priority among available sites. Therefore 600 MW Maha site was selected as the first site to develop a PSPP in Sri Lanka and a feasibility study (2024) was carried out on the site.

The Wewathenna Pumped Storage (2 x 350 MW) has been considered as candidate for selection in the base case after the development of (3 x 200 MW) Maha Oya Pumped Storage but is not selected due to the higher cost compared with other alternative options.

5. **Reason for the significant increase in the capital costs of the Wewathenna and Maha Oya Pumped Storage Plants, with increments of 167% and 33% respectively compared to the cost applied in the LTGEP 2023-2042.**

As explained in clarification 4, the cost figures were updated in the recently completed pre-feasibility study with ADB assistance for both sites and respective cost have increased pertaining to updated site conditions and global equipment and labor prices.

6. **Reason for the delay in implementing the HVDC interconnection from 2034 to 2039, as compared to the schedule in the HVDC Interconnection scenario in the LTGEP 2023-2042.**

During the recent DPR study conducted with POWER GRID India, the previous overhead sea cable design was changed to underground sea cable design, which contributed to a high increase in capital cost. Hence the capital cost of the project has increased to 1,225 million USD. Due to the high investment requirement the project is pushed to later part of the horizon.

Since the development of BESS and PSPP (Maha) provides sufficient storage requirements to satisfy the policy targets, further large-scale investment on energy storage or power exchange are not required to cater the projected demand up to year 2039. However, the proposed interconnection at a cost of 1,225 million USD becomes more viable than developing the alternate PSPP site (Wewatenna) or BESS as evident in Scenario 1 and 2. An advancement of the HVDC interconnection is observed up to year 2037 if renewable energy absorption is increased above 70% as observed in scenario 4, however this scenario is expensive than the base case scenario.

7. **Has the capital cost for the LNG infrastructure been included in the capital cost of the natural gas candidate technologies?**

No. It is included as capital cost to be incurred in the middle of year 2027 for all scenarios.

The cost details related to LNG Infrastructure with the escalations are as follows. CEB shall take necessary action to include this in chapter 4 of the amended report.

	CAPEX (2024 base) (Million USD) ***Used in the Plan***
FSRU	250
Mooring Facility	34
Pipeline (offshore and Onshore)	40
Total	324

8. **What is the basis for the net generation forecast of 21,444 GWh in 2025 and the forecasted 5-year average net generation growth rate of 5.3%, as per the time trend demand forecast (Table A3.3), given the negative average net generation growth rates of -3.2% and -0.4% for the last 3 and 5 years, respectively (Table 3.1)?**

Long Term Time Trend models generally assume constant growth rate which smooths out data over time. However, external factors such as the pandemic and economic downturns have indeed caused irregularities in recent years.

Model is derived based on following equation

Demand = a (1+g)^t

Where

a : Initial value or the base demand at the starting time. It represents the demand level when t=0.

g : Constant growth rate which reflects the average annual growth in demand over the period of the data set assuming that demand grows at a fixed percentage each year

t : time in years

For the linearized equation:

$$Ln(Demand) = Ln\ (a) + t\ .\ Ln(1+g)$$

Using demand data from 1998 to 2022 (25 years), a constant growth rate (g) of 5.3% is derived, through the regression of the natural log of demand (dependent variable) on time (independent variable). This linearized form allows the growth rate to be estimated more accurately, considering historical trends that are relatively free of random fluctuations or anomalies such as pandemic and economic downturn.

Hence as explained above random variations such as the reduction in the demand in the recent years have been smoothen out from this model.

Please also note that, Table 3.1 depicts the electricity sales excluding self-consumption and energy not served. However, in the demand forecasting process adjusted demand is considered.

9. What are the identified six candidate sites for the nuclear power plant?

According to the latest update by the time LTGEP 2025 – 2044 submitted; six sites were identified as most suitable sites for nuclear power development. However, as per the latest developments of the studies the number of potential sites has been reduced to three after further screening. Presently finalized sites are

i. Pullmoddai
ii. Mullativu site-near Phara ship
iii. Kal-Aru site near Mannar

Please note that this will be updated in LTGEP as appropriately.

10. Is the implementation of HVDC interconnection between India - Sri Lanka and Pumped Storage Power Plant a mandatory prerequisite before the integration of the nuclear power plant?

Yes, it is mandatory to have the HVDC interconnection as well as the pumped storage units implanted to allow safe operation particularly during off-peak conditions. In addition to the to operate in high inverter based periods, synchronous condensers and fast frequency response services shall be required.

11. Reason for not considering the integrated storage solution coupled with large scale fully facilitated solar PV parks (Grid Connected Fully Facilitated Solar with BESS), which was included in the plant schedule of the LTGEP 2023-2042.

In this iteration there is no restriction imposed on the development of BESS as either stand alone or coupled with solar parks. It is to be decided at the procurement stage depending on the viability of site conditions and system requirements. The co-location of BESS with solar parks can have capital cost savings.

However, it is important to unbundle the operation of BESS from the operation of solar parks. All BESS facilities are required to operate separately on dispatch instructions as requested from

National System Control Centre. They are required to supply energy in any timeslots as requested by the dispatch instructions in addition to providing fast frequency response services throughout the life cycles.

12. What Demand Side Management (DSM) measures are recommended for implementation by the distribution licensees as per the DSM implementation plan?

Implementation of DSM measures mainly depends on the customer and the utility has minimal control over it. Initiatives in the DSM implementation plan are mainly managed by the SEA as the agency responsible for DSM implementation. How ever the cooperation of utility is provided as and when required by SEA and there is no stringent plan on this. The following are examples of the DSM initiatives to which utility can contribute,

i. Introducing demand response schemes
   - Offer a kW and/or kWh-based incentives to customers who are willing to participate in Automated demand response schemes
   - Manual load deferment using automatic time-based switching operation for water pumping, conveyor equipment etc
ii. BESS assisted load management
   - Designing ToU tariffs to open a window of opportunity for BESS to be viable
iii. Customer education and information campaigns.

13. Reason for limiting the extension of the retirement year for Sapugaskanda A, Sapugaskanda B, and the Barge power plants to only 5 years after their refurbishments

It is to be noted that the extension of these power plants is required due to reserve margin shortage from year 2026-2027, provided the other power plants are implemented on time. Furthermore, there are economic benefits of operating the furnace oil power plants until the natural gas infrastructure is made available in the country.

In order to continue the operation of these power plants beyond 2026, they are required to be refurbished. Once these refurbishments are completed the power plant can operate for further five years. However, it is to be noted that these plants are inflexible and as more VRE is integrated to the system, operation of such inflexible plants are required to be replaced with flexible generation. If the LNG infrastructure and power plants as base case are implemented on time, there shall be no requirement to further extend these power plants beyond year 2030. However, this can be further validated, in subsequent planning cycles based on the requirement and plant condition.

14. Does the estimated local gas price (8.5 to 10 USD per MMBtu) by PDASL include the handling charges? If not, what is the estimated handling fee per MMBtu?

The price estimated by the PDASL refers to the gas delivery price to Norochcholai area, which is in close proximity to the Mannar gas basin. The local gas available at the Mannar basin is in gaseous form and there is no requirement to be converted to LNG. Hence there is no requirement of establishing a FSRU. The only cost associated with the handling charge is for the development of offshore pipeline from Mannar basin to western region. An approximate cost figure is used as capital cost in planning studies as mentioned in section 10.21 in chapter 10

15. What are the estimated plant factors and the specific costs of the candidate ORE technologies?

In this iteration of planning studies VRE plant technologies were allowed to have stochastic variation based on historical data, which results in a range of annual plant factors. Furthermore, for wind plants the plant factors depend on the selection of wind turbine and appropriate hub height for each specific location. The estimated plant factors and respective specific cost of candidate ORE technologies are as follows.

<table>
<tr><th colspan="2">Technology</th><th>Plant Factor (Apprx.)</th><th>Specific Cost UScts/kWh</th></tr>
<tr><td colspan="2">Solar (Large Scale)</td><td>20%-23%</td><td>5.58-6.42</td></tr>
<tr><td colspan="2">Solar (Distributed)</td><td>16%-18%</td><td>7.87-8.86</td></tr>
<tr><td colspan="2">Floating solar</td><td>19%</td><td>9.9</td></tr>
<tr><td rowspan="4">On Shore Wind</td><td>Mannar</td><td>38%-44%</td><td>5.32- 6.16</td></tr>
<tr><td>Northern</td><td>34%-37%</td><td>6.33-6.89</td></tr>
<tr><td>Puttalam</td><td>32%-35%</td><td>7.32-6.69</td></tr>
<tr><td>Eastern</td><td>27%</td><td>8.67</td></tr>
<tr><td rowspan="2">Off-shore wind</td><td>Fixed</td><td>45%-50%</td><td>12.73-14.14</td></tr>
<tr><td>Floating</td><td>45%-50%</td><td>17.63-19.59</td></tr>
<tr><td colspan="2">Biomass</td><td>50%</td><td>6.41</td></tr>
<tr><td colspan="2">Mini hydro</td><td>37%</td><td>8.09</td></tr>
</table>

16. Why wasn't a cost variation trajectory not used for ORE technologies over the planning period?

As stipulated in Grid Code constant prices are been utilized to derive the main planning scenarios. Hence cost variations with time are not considered in developing main scenarios. However, CEB does acknowledge the importance of considering the cost projection, hence have conducted sensitivities of cost variation with time for projected generation technologies and fuel as published by the IEA. These results are already published in section 8.4.2. of LTGEP 2025-2044

(ii) Clarifications via Letter Reference GP/CE/EXPAN/2023 dated 18th December 2024

1. **ls the capital cost of the LNG Floating Storage Regasification Unit (FSRU) used in the plan different to the price quoted for the tender floated in 2021? If not, please provide a capacity and cost comparison.**

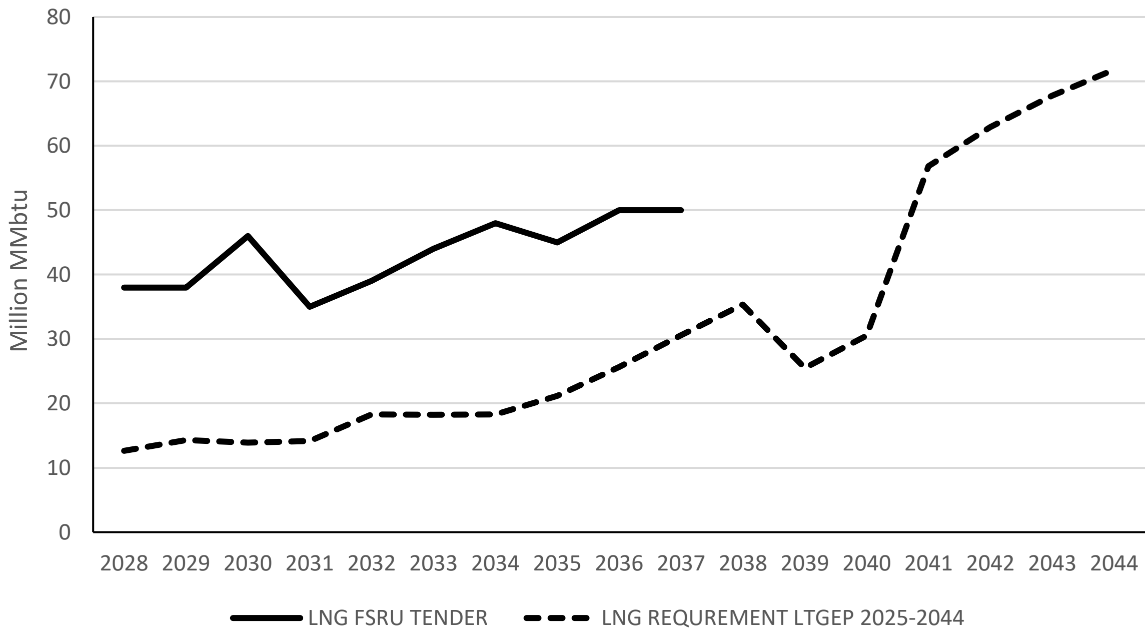
   The capital cost of LNG infrastructure for the LTGEP 2025-2044 is derived from the ADB-funded feasibility study titled *"Development of LNG Infrastructure for Power Generation in Sri Lanka,"* completed in 2020. The original project cost of USD 285 million has been escalated to reflect 2024 prices, resulting in a revised capital cost of USD 324 million. These costs are presented on an economic basis and align with the typical range for an FSRU in the current market. In contrast, the tender offer received in 2021 is based on financial terms, including cost of financing, profit, taxes, and other factors, with an annuity payment of approximately USD 100 million over 10 years to cover both capital and operational expenditures for the LNG infrastructure.

2. **Source for LNG FSRU cost estimation.**

   As answered above in (1).

3. **Does the forecasted LNG consumption in the plan align with the tendered capacity of the FSRU? If so, please provide a comparison.**

   The forecasted LNG consumption in the plan does not align with the tendered capacity of the FSRU. The LNG consumption expected in the tender is higher than the forecasted LNG requirement in the draft LTGEP 2025-2044. This is mainly due to the change of policy directive which is more favorable for renewable energy and decrease in projected demand due to the economic recession. The comparison of annual fuel quantities are as follows.



4. **Given the low plant factors of the NG power plants (As mentioned in the Annex 10.3 of the plan) can the forecasted LNG consumption fulfil the minimum purchase obligations stipulated in the above tender agreement? Please provide a gap analysis for each year and FSRU capacity charge/MMBTU based on the tender pricing.**

   The LNG fuel procurement and development infrastructure is unbundled. Hence the minimum purchase obligations are only a method used to reflect capital cost recovery to the project proponent for the FSRU, and has no linkage to actual fuel procurement. In other words, for the tender regardless of the fuel quantity procured an annuity payment of approximately USD 100 million over 10 years is required to be paid to the developer. This is considering a 2.7 USD/MMBtu capacity charge for FSRU and the minimum purchase obligation of LNG fuel quantity as stipulated in the graph in question 3. Gap analysis for LNG quantity is also shown in the graph in question 3.

5. **The method of LNG procurement after the 10th year of the plan and the costs considered for 11th year onwards (Considering the LNG FSRU to be operated under a Build-Own-Operate model for 10 years)**

   The typical design life of a FSRU shall range from 20-40 years considering the options of conversion of LNG carrier vessel or newly build FSRU. Hence the FSRU and LNG infrastructure procured as an asset at economic cost of USD 324 million is sufficient for operation beyond 10 years.

   However, the business model considered in commercial terms for the tender considers the operation of FSRU in BOO terms of 10 years. Beyond 10 year operation the same could be either extended or go for an alternative option. This will be addressed in future cycles of the plan.

6. **For the period starting from the year 11 of the plan, does the LNG FSRU utilize the same capacity of the planned FSRU? If not, what is the additional costs associated with procuring a new FSRU and a new mooring system, as it is unlikely that the same mooring cost would be applicable for a new (and different sized) FSRU?**

   The FSRU regasification capacity of 375 MMSCFD is sufficient to cater the daily natural gas requirement of year 2044. However, the frequency of procuring LNG cargo ships shall increase gradually. Hence there is no requirement for procuring a separate FSRU or Mooring system beyond 10 years.

7. **Reason for excluding the capital costs of LNG FSRU and mooring from the fuel cost of the candidate NG plants as done in the LTGEP 2023 2042, and including as a central capital cost, which would result in the software to suboptimize the plant selection.**

   As already explained to PUCSL in Input data clarification, the annual requirement of natural gas quantity varies significantly in planning scenarios and is not justifiable to apportion a single value as handling cost for fuel, to recover the investment cost. Since this is an investment cost and not an operational cost, this provides improved way of modelling the same. It does not result in a suboptimization for the plant selection.

8. **Estimated capacity cost (per MMBTU) for the pipeline infrastructure for the plants to be converted**
   to NG technology at Kelanithissa for each year based on the pipeline investment cost calculation.

   The estimated capital cost of pipeline from Kerawalapitiya to Kelanithissa is 18.7 million USD in 2024 prices. (This is included in LNG infrastructure cost of 324 million USD). Accordingly, capacity cost for pipeline serving the power plants at Kelanithissa, based on the plant line-up based on draft LTGEP 2025-2044 is as follows.

Period	Average Cost USD/MMBtu
2028-2032	7.69
2033-2037	1.78
2038-2042	0.55
2043-2044	0.17

   By implementing new capacity additions in the base case of draft LTGEP 2025-2044, the electricity generation from Kelanithissa power plants to be converted to NG are minimal. Initially, the generation from converted power plants at Kelanitissa is minimal and with the introduction of new gas turbine power plants, generation from Kelanitissa premises increases. Hence, the average capacity cost of the pipeline gradually decreases.

9. **Basis for setting a maximum allowable limit of 75% for System Non-Synchronous Penetration (SNSP) level during the planning horizon**

   While inverters are anticipated to provide fast frequency response services, certain amount of synchronous inertia is required to limit the ROCOF in frequency disturbance events. The 75% limit reflects current technological capabilities while allowing for incremental increases as innovations become widespread. Increasing SNSP further can reduce curtailments and improve operational cost savings. However, it is mandatory to conduct further detailed studies to evaluate the impact on the power system to gradually achieve higher SNSP limits phase by phase. As illustrated in figure 10.7 of draft LTGEP, The SNSP from generation is gradually increased up to 80% in years beyond 2030.

10. **Results of a sensitivity analysis conducted under Section 8.4.2 (Cost projection sensitivity) without imposing a SNSP level.**

   The present value cost of the key scenarios considering cost projections and without SNSP limitations are presented below.

Scenario	**PV Cost of Investment (MUSD)**	**PV Cost of Operation (MUSD)**	**Total PV Cost (MUSD)**
Scenario 3 (Base Case)	7,619	5,474	13,093
Scenario 5 (80% RE)	8,695	4,927	13,621
Scenario 7 (Reference)	5,788	7,180	12,968

11. Specific cost calculation methodology for the Natural Gas & Hydrogen blended plants.

Same methodology as specified in the Annex 7.2 of the draft LTGEP 2025-2044 has been used. For the derivation of fuel price of the blended fuel, 25% hydrogen by volume for the IC engines and 30% hydrogen by volume for the combined cycle and gas turbine power plants was considered along with the price of each fuel.

12. Is all the Hydrogen fuel planned to be used, green hydrogen and locally produced? If yes, the renewable energy source utilized for its production and whether it is accounted for in the generation capacity plan.

In the aim of achieving carbon neutrality by 2050 and other NDC targets, Petroleum Development Authority of Sri Lanka has developed a comprehensive report on Sri Lanka's National Hydrogen Roadmap which outlines the national hydrogen implementation strategy of the country. However, policy and regulations on green hydrogen production/procurement are yet to be developed. It can be either imported as a fuel or developed locally from the renewable energy sources. Considering the aggressive renewable energy deployments planned in the future, the likelihood of having large amounts of curtailments is unavoidable. These curtailments can be reduced by using the same for hydrogen production through PEM electrolyzers. These electrolyzers can be operated flexibly allowing smooth integration with variable renewable energy sources. Hence, there is no requirement for additional renewable energy capacity to produce the hydrogen demand for electricity generation. However, considering the progress of the green hydrogen roadmap, if hydrogen is to be produced for export purposes, the required renewable energy capacity must be evaluated based on the anticipated quantities of hydrogen production.

13. How the energy imports through the HVDC interconnection are treated are accounted into the CO_2 calculations in pathway to Carbon Neutrality?

In the Production-Based Accounting method emissions are attributed to the exporting country, where the electricity is generated. The importing country does not include these emissions in its GHG inventory, even if the electricity is consumed domestically. This approach avoids double-counting emissions between countries and aligns with international reporting standards. However, during project implementation, emission-sharing agreements may be established, upon the mutual consent of both countries, and outlined in the corresponding implementation agreements.

14. The contingency plan/analysis for the safe operation of the nuclear plant in the event of a HVDC interconnector failure

The event of a nuclear power plant tripping during an off peak condition, when the HVDC interconnection is unavailable could create a system stability concern. As first step, to prevent creating a potential blackout, the nuclear power plant is required to operate in minimum load conditions during such period. Due to the economical benefits nuclear power plants are designed to operate in baseload with minimum deloading capability. However, modern day nuclear power plants that are already operational in countries like France are capable of delaoding up to 15-50% of maximum capacity. In addition, they are capable of load following and frequency support services as well. Hence such capabilities are required to be incorporated in design of nuclear power plants.

However, if the contingency of blackout does occur during this period, alternate power source other than grid is required to provide power for safe shutdown of the nuclear core. The alternate power source shall have the black start capability and supply the necessary power to preserve the integrity of the reactor coolant system and prevent damage to the core. All these issues will be addressed during the design phase of the nuclear power plant.

(iii) <u>Clarifications via Letter Reference GP/CE/EXPAN/2023 dated 10th March 2025</u>

Section A

1. **More robust and realistic cost assumptions for Renewable Technologies and Battery Energy Storage Systems (BESS), adjusted to the local conditions shall be used, as the Renewable Energy costs used in the plan do not align with the current market prices and global trends due to the significant cost changes over the 12 months of the planning process**

Prior to commencing the planning studies CEB had requested PUCSL concurrence on input data and the same was provided in January 2024. However, we acknowledge the PUCSL observation on the reduction of cost of renewable energy and battery energy storage technologies during the past 12 months. To reflect possible cost reductions CEB had already conducted sensitivity studies and incorporated in chapter 8 of the LTGEP report. Subsequently further analysis of cost reductions without limiting SNSP was requested by PUCSL and relevant response were provided through letter references GP/CE/EXPAN-2023 dated 2024-12-18.

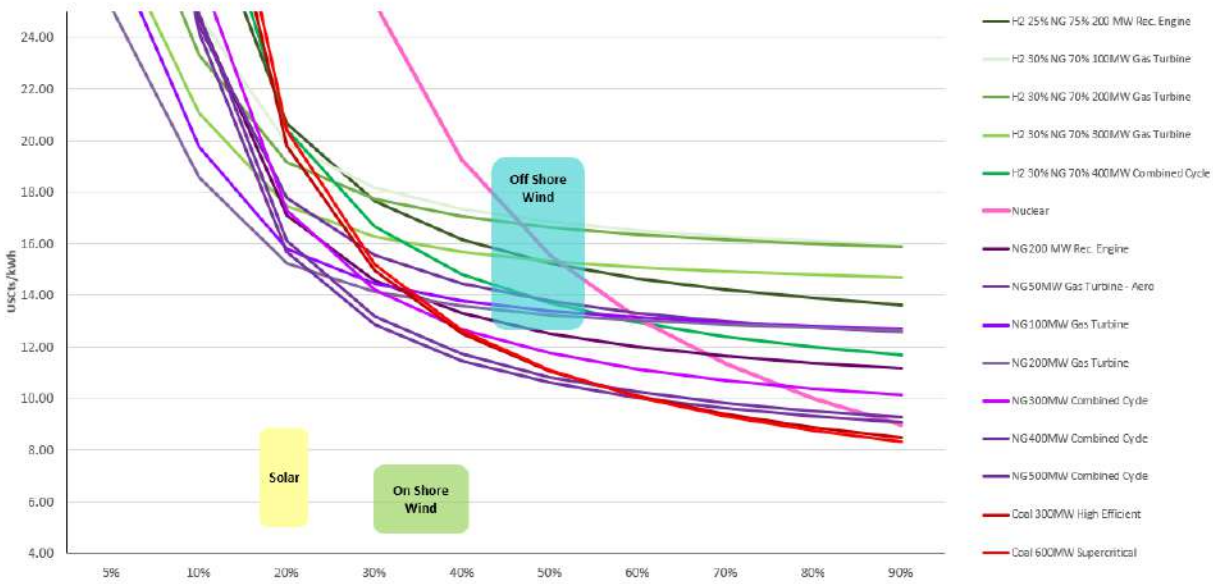


Figure 1 Specific cost of candidate technologies

It is to be noted that the specific cost of main renewable energy sources already modelled in the LTGEP are lower than all other thermal technologies as shown in figure 1. Hence, they are already the lowest cost, in the merit order and further reduction in cost does not change the selection of alternate technologies that affect the power plant schedule in Base case Plan. However, furthermore reduction in renewable energy sources would further reduce the overall cost of the scenarios considered in the LTGEP.

Supplementary information in regard to this is supplied in Section B of this report.

2. **Plant lifetime and Depth of Discharge (DoD) of BESS shall be reviewed**

The calendar life and life cycles of BESS systems are two separate parameters that require to be assessed separately. The calendar life of modern battery energy storage systems can reach around 20 years. However, there actual life time depends on the usage of the BESS system dependent on how much cycling it's done. Often higher the depth of discharge results in lowering the life cycle capability of battery cells.

Certain Lithium Ion Phosphate (LFP) BESS manufactures provide estimates in life cycles from 3,650 to 7,300, with some capacity degradation over life time. This results in variation of 10 to 20 years of daily cycling possibility without explicitly mentioning the depth of discharge.

BESS identified in LTGEP are expected to provide primary and secondary frequency regulation services in addition for energy shifting capability. They will provide fast frequency response services and in some instances are expected to maintain the frequency response until replacement reserves are dispatched. Hence, 80% of the energy capacity is allocated for energy shifting (10% to 90% SOC) and remaining energy capacity required to be kept reserved for other ancillary services. Hence 100% DOD capability is required from all BESS systems.

In the LTGEP BESS has been modelled considering a 10 year lifespan and with the replacement of similar capacity BESS upon the expiry of 10 years lifetime. In the context of unavailability of accurate data , additional sensitivity is conducted for extended lifetime of BESS for a period of 20 years and results of the are depicted in Section B of this report.

3. **More realistic timeframes shall be included for the development and commissioning of the LNG Infrastructure (FSRU and the pipeline network) and for the commissioning of the second NG based Combined Cycle Power Plant of 350MW at Kerawalapitiya**

The timelines specified in LTGEP are based on the information available as at April 2024. However, based on the implementation progress of each power plants they can lead to further delaying the commissioning date of the power plant. Such changes are to be captured in subsequent planning studies. However, the contingency analysis on chapter 13 of the LTGEP report already addresses the possible impacts in delays of power projects (including second 350 MW CCY at Kerawalapitiya) with potential remedial actions for each risk event. Similarly, impact of delay in LNG infrastructure has been assessed in chapter 10. The possible LNG infrastructure availability in present context would be in year 2028.

4. **The financial/technical clauses and plant factor commitment of the MOU signed with Petronet India to develop a temporary LNG supply to Sobadhanavi Plant shall be incorporated**

There is no commitment through the MOU with Petronet India on temporary LNG supply. The cabinet decision 24/2119/825/007 dated 2024-12-19 has approved the recommendation to proceed with the aforementioned proposal as short term solution to be implemented through Ceylon Petroleum Corporation.

However, the natural gas requirement is not to operate a single power plant at baseload, but to have the option to operate several plants at cyclic patterns with daily start stop capabilities.

The fine details of the refined proposal have not been disclosed yet and is required to be reevaluated by the assigned committee. The Draft LTGEP shall provide insight on anticipated natural gas fuel requirements, operating patterns for such evaluations.

5. **Conduct a comprehensive analysis covering the following, and include FSRU and pipeline costs in the LNG fuel cost calculation accordingly, without treating the infrastructure costs as a separate capital investment**

   a. LNG infrastructure development

The permanent solution to supply natural gas is been considered with the development of FSRU and pipeline to Kerawalapitiya to Kelanithissa. As per the received offer an annuity payment of approximately USD 100 million over 10 years is required to be paid to the developer for FSRU, mooring and pipeline development.

The commission observation in incorporating infrastructure cost to fuel cost is inappropriate, as this is purely a capital cost which has to be paid regardless of the consumption. Hence such investments are required to be modelled as capital investment as done for other power projects including solar, wind, other RE, thermal and storage projects.

However, for indicative requirements, per unit infrastructure cost for already identified fuel quantitates in base case plan are as in Table 1. They are subject to change if fuel quantity requirements change.

Table 1 Indicative Terminal Cost for Base Case Fuel Requirements

Period	Average Cost(USD/MMBtu)
2028-2032	6.7
2033-2037	5.0
2038-2044	2.2

   b. LNG procurement contracting options

The fuel supply of LNG can be procured through

a. Medium/ long term contracts which is indexed to crude oil for bulk orders.
b. Spot market for individual orders.

The historical variation of LNG price through the past are indicated in figure 2.

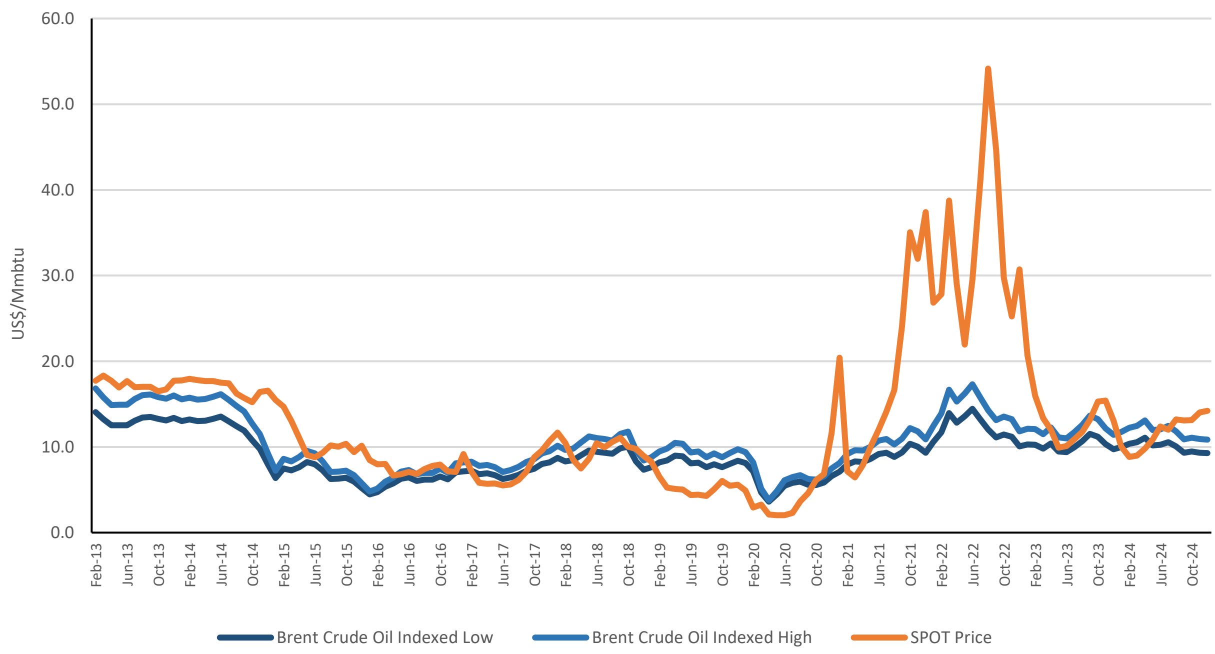


Figure 2 Historical Natural Gas Price Variation

The spot market prices are generally high compared to indexed prices, but can be lower during certain periods. There were exponential price hikes in spot market during the global economic events incurred during 2021-2022 period. The indexed prices are more stable and are generally lower than spot market prices. The per unit cost savings for potential thermal technologies, considering the above natural gas price variations with the price variations of oil during the same period, are illustrated in figure 3.

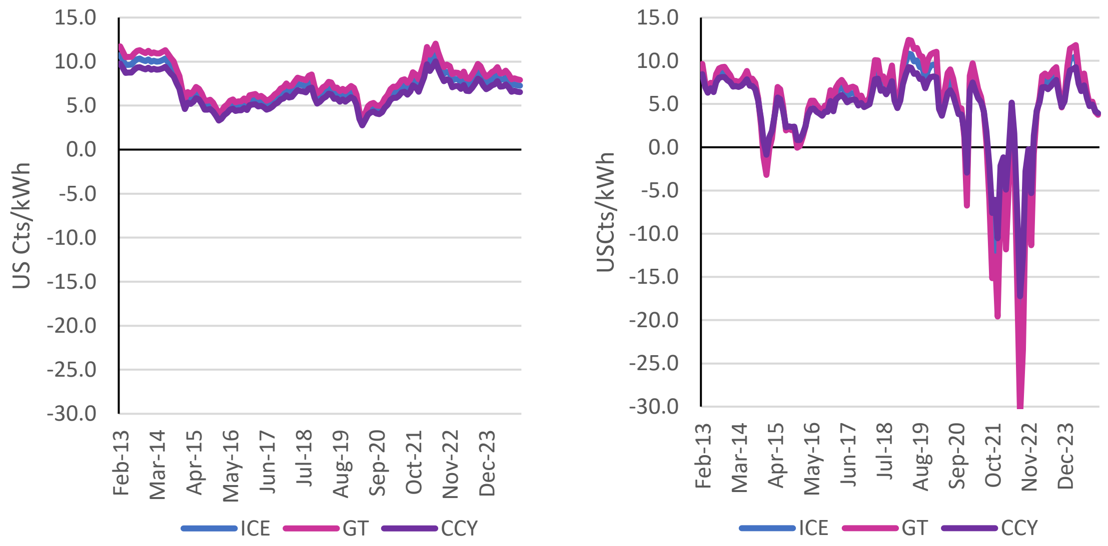


Figure 3 Fuel Cost Saving from Natural Gas Conversion

c. Risks associated with the LNG supply and procurement

The expected annual cost savings for base case, after accounting for the annuitized investment cost for LNG infrastructure from the received offer, based on average fuel cost savings derived from historical prices for full procurement from the spot market and full procurement through medium- or long-term contracts, are shown in figure 4.

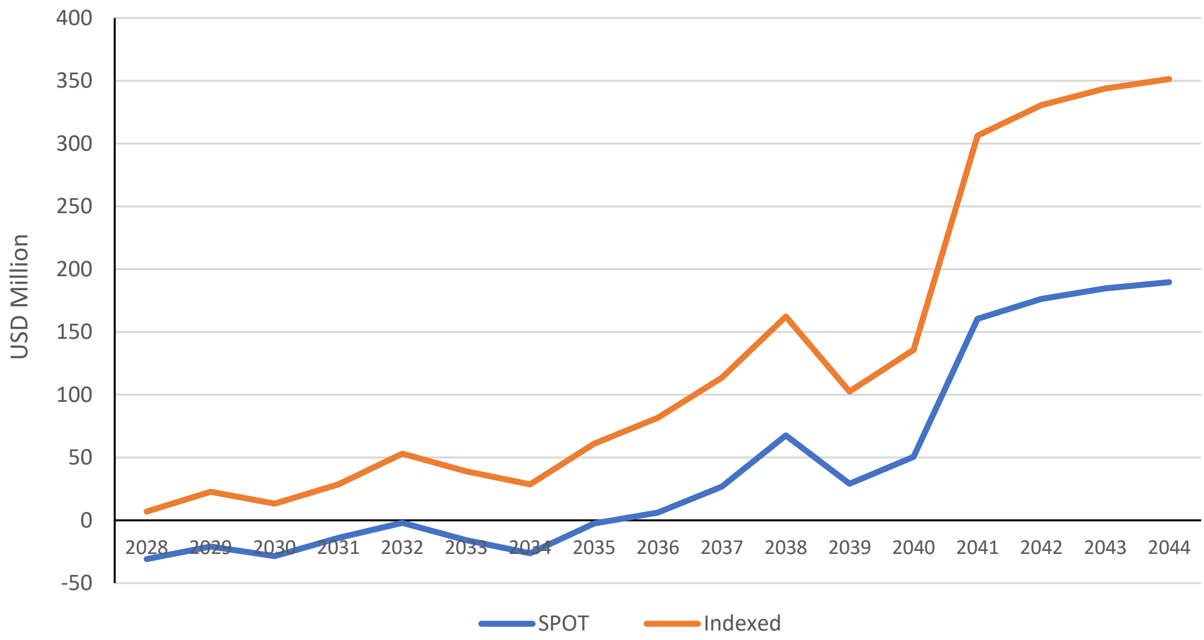


Figure 4 Annual Cost Savings Variations

If the planned renewable energy targets as planned in the Base Case Plan are achieved on time, the complete procurement from spot market possesses the risk of an economic loss due to the volatility of natural gas price variations in spot market. However, if LNG is expected to be procured through an index annual cost savings can be expected every year. Hence it is critical to establish medium to long term contracts for the required fuel quantity. Examples of LNG fuel procurements for similar capacity medium to long term contracts are as follows.

1) Gorgon Gas Project in Australia, Chevron Australia signed a long-term LNG sale and purchase agreement with GS Caltex of South Korea. This agreement entails the supply of 0.25 MTPA of LNG over a 20-year period.
2) Chevron Australia entered into a 15-year agreement with Kyushu Electric to supply 0.3 MTPA of LNG from the Gorgon Gas Project.
3) ADNOC Gas signed a 10-year Sales and Purchase Agreement (SPA) with GAIL India Limited to supply up to 0.52 MTPA of LNG, commencing in 2026.

In addition, having contracts through LNG Aggregators, who provide medium to long-term contracts distributing the LNG to multiple buyers are options that can be pursued.

Petronet, in its proposal for 0.25mtpa for Sri Lanka, has indicated a 13% slope to the Brent index, which accounts for their costs related to LNG importation, storage, re-exportation, and associated taxation. However, if the same LNG cargo is redirected directly to Sri Lanka through Petronet, the overall cost should be significantly lower than a 13% slope due to elimination of additional import and re-export costs, reduced storage, handling charges and lower taxation burdens.

d. Robustness of the NG demand calculations

The natural gas demand is dependents on the realization of planned renewable energy and storage projects as well as the expected growth in demand. It is to be noted that the expected quantities of natural gas have drastically changed over time due to the changing of policies in renewable energy integration targets. Furthermore, the situation has further changed due to the reduced demand expectations after the occurrence of economic recession in year 2022. The expected variation of natural gas requirements under above sensitivities is illustrated in Figure 5

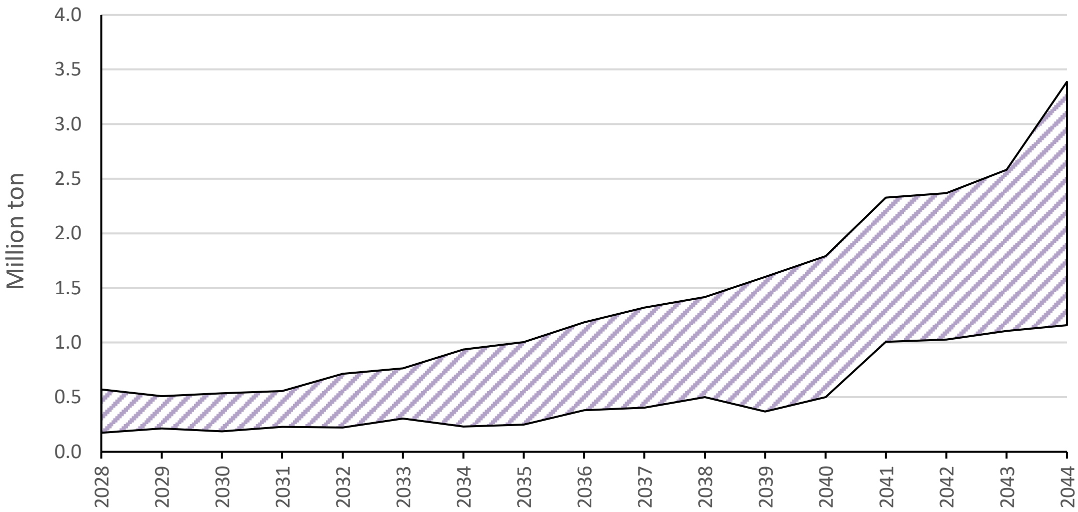


Figure 5 Potential LNG Requirement Variation

Furthermore, as explained in Section 10.17 of LTGEP 2025-2044 report, in the event of aggressive EV penetration is expected in future, the fuel requirement from natural gas would further increase. Although, if tariff instruments are properly set to allow charging during low cost time periods during the day time, majority of public transport and some private transport shall depend on night time off peak charging which is generated through natural gas.

In addition, the natural gas requirement is highly seasonal with, majority of the requirement incurring during the dry season (Jan-April) of each year and end of the year. The main reduction of fuel requirement during months from May to August is due to the implementation of planned wind power projects. If the wind power projects development is delayed, higher fuel requirements can be expected during these months also.

The natural gas requirement can vary within the day, as even the combined cycle thermal power plants may operate in daily cycling mode. This is due to the increased penetration of solar power during the day time, while night peak is dependent on thermal generation. It is important to have a common storage and supply for all power plants, which would allow unconstrained economical operation of the power plants according to the system operational requirements.

e. Financial and economic viability of the natural gas pipeline from Kerawalapitiya to Kelanithissa complex, given the low plant factors of the power plants at Kelanithissa

The new power plants operated at Kerawalapitiya are of higher efficiency than the existing plants at Kelanithissa. There is considerable demand reduction as well as higher share of renewable energy projects planned. Hence, power plants at Kelanithissa are operated at a lower plant factor within the merit order dispatch in initial years. Hence the natural gas requirement for power plants at Kelanithissa are minimum. The indicative capacity cost of pipeline considering the usage was already clarified in previous letter reference GP/CE/EXPAN-2023 dated 2024-12-18.

6. **The possibility of further reducing the Renewable energy curtailment by incorporating more BESS shall be assessed**

In order to reduce the renewable energy curtailments, it is first necessary to identify the renewable energy generation and curtailment patterns.

Renewable energy additions are mainly provided by solar and wind energy sources, as complete potential of hydro resources have been harnessed. Solar energy is available throughout the year during day time, but has reduced production at the end of the year in wet season. Wind power generation in all area of Sri Lanka follows a distinct seasonal pattern, with the majority of energy produced between May and September, while output in other months remains low to moderate. Even though hydro plays a major role in present power system operations as the demand grows the impact of hydro energy would reduce due limited growth in new additions.

1. Curtailment during the dry season (January to April) is relatively ***low*** and occurs mainly during *daytime in Sundays and holidays,* where the demand is comparatively low.
2. Highest Curtailment during the year is observed during the ***high*** Wind Season (May-September). The curtailment is mostly during *daytime in in both weekdays and weekends* where solar production and wind production overlap. There can be *occasional curtailments during off-peak* times during this season where wind production is very high.
3. Curtailment during the wet season (October-December) is also relatively ***low*** with curtailment mainly observed during *daytime in Sundays and holidays*, where demand is comparatively low.

The replacement of battery energy storage can introduce reduction of curtailments but it cannot be completely mitigated. By replacing thermal sources with BESS, reliability violations with insufficient resource adequacy is created. This is mainly during wet season and some times during dry season. As shown in Figure 6, it is important to note that even in the proposed base case plan, there are periods where renewable energy generation is insufficient to charge the BESS. During these times, storage systems may need to be charged using thermal resources to meet the night-time peak demand.

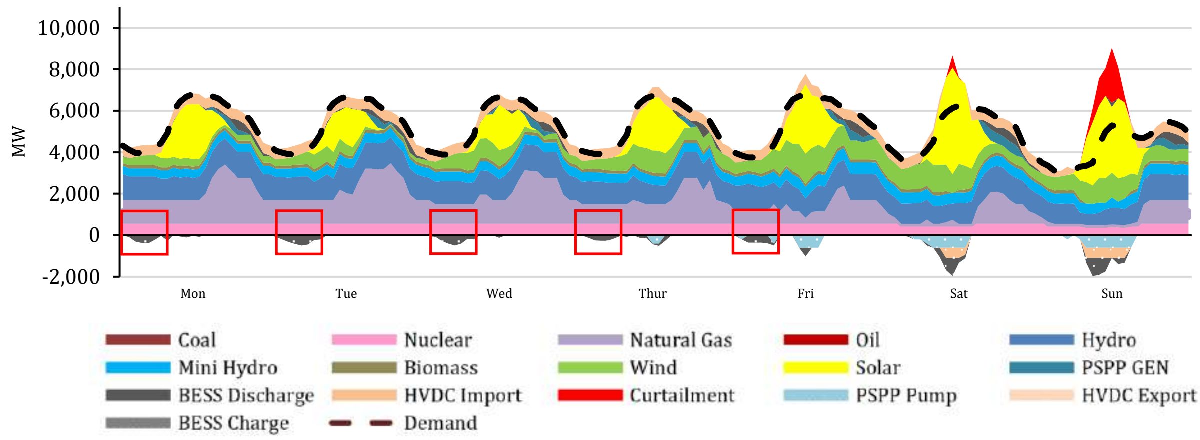


Figure 6 Weekley Dispatch pattern in renewable drought

Further replacement of thermal power plants through BESS can further aggregate this issue creating higher risk on ensuring reliable power supply to the system.

However, reliability can be improved if BESS is deployed alongside additional renewable energy capacity, ensuring higher cumulative energy production during periods of renewable energy droughts. At the same time, these additional renewable energy installations shall lead to increased curtailments during high-wind seasons and, at times, in the dry season.

As per the request of the commission, impact of incorporating additional BESS is illustrated through following potential scenarios.

Scenario 3 : Base Case Plan (20 year additions :Thermal 4,000, BESS 900, ORE 10,700)

Scenario 3B: Replace thermal Capacity additions, with BESS systems. ORE capacity is maintained the same. (20 year additions :Thermal 2,800, BESS 2,300, ORE 10,700)

Scenario 5 : Increase the capacities of both ORE and BESS, while reducing the thermal capacity. (20 year additions : Thermal 2,800 + BESS 2,100 + ORE 13,700)

The impact of BESS on potential reductions in renewable energy and system reliability is illustrated in Figure 7. In Scenario 3B, marginal reductions in renewable energy are expected without significantly affecting system reliability until 2035. Beyond this point, curtailments decrease notably but cannot be fully mitigated. However, replacing thermal capacity has a substantial impact on reliability, exceeding the maximum Loss of Load Probability (LOLP) limits. This issue can be partially addressed by increasing renewable capacity alongside BESS expansion, as seen in Scenario 5, but reliability violations persist beyond 2040. While additional renewable capacity improves reliability in certain periods, it also increases curtailment significantly during others periods, further complicating efforts to manage curtailments effectively.

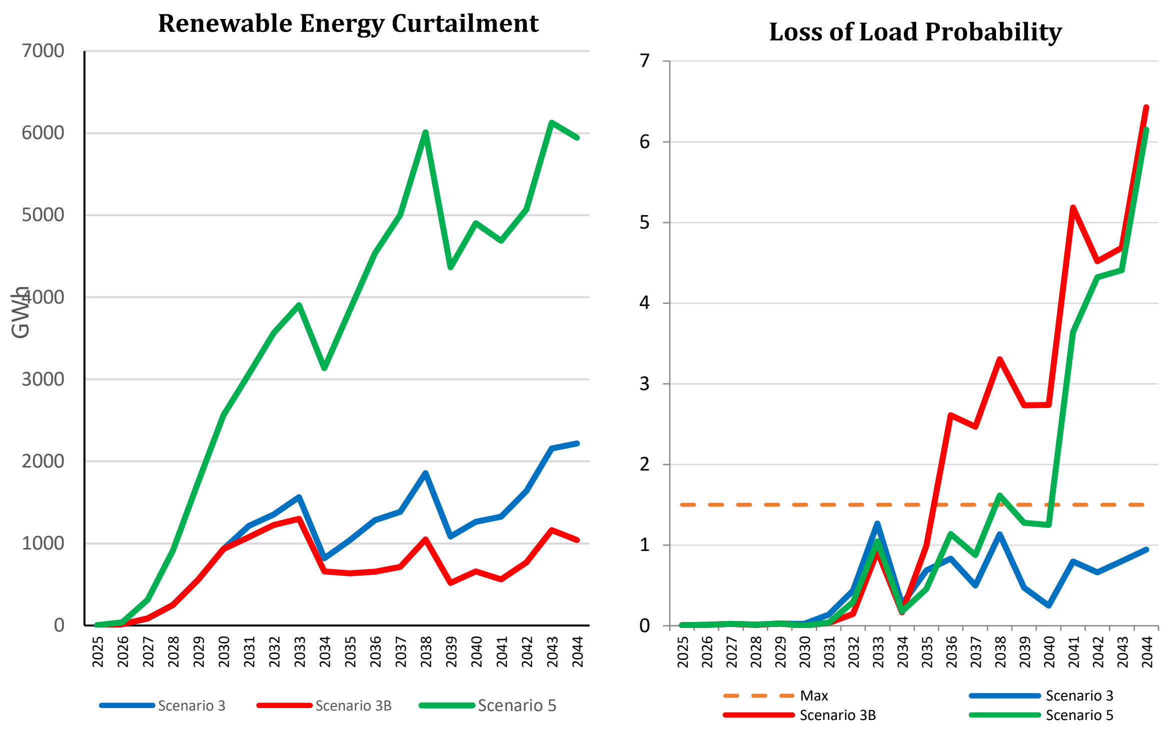


Figure 7 Curtailments and Reliability

Furthermore, it is to be noted that Forced Outage Rate of BESS or renewable energy projects have not been considered in this analysis and reliability indices are based on complete renewable resource availability during each period.

In order to evaluate the impact on additional BESS to the power system following analysis is illustrated by considering the policy year of 2030. The incremental capacity of 100 MW/400 MWh BESS are considered in year 2030, to depict potential curtailment reductions and annual cost savings as shown in Table 2.

Table 2 Impacts of BESS Incremental Additions

Incremental Addition	Annual Incremental Curtailment Reduction per 100 MW/400 MWh BESS (GWh)	Annual Incremental Operating Cost Savings per 100 MW/400 MWh BESS (Million USD)
+ 100 MW/400 MWh BESS	105	13
+ 200 MW/800 MWh BESS	91	13
+ 300 MW/1200 MWh BESS	83	6
+ 400 MW/1600 MWh BESS	75	9
+ 500 MW/2000 MWh BESS	65	7

The annual cost savings are to be compared with annuitized cost of BESS installations under different capital cost and various life expectancies of potential BESS technologies are tabulated in Table 3.

Table 3 Cost Variations of BESS

BESS Cost and Expected Lifetime	Annuitized Cost for 100 MW/400 MWh BESS
@ 364 US$/kWh 10 years	27
@ 300 US$/kWh 10 years	22
@ 300 US$/kWh 20 years	16
@ 200 US$/kWh 10 years	15
@ 200 US$/kWh 20 years	11

It can be noted if BESS projects with extended warranty that can operate for a period of 20 years can be procured below a cost of 200 US$/kWh there can be marginal economic benefits. Hence provision to procure BESS capacities identified in Base Case Plan before year 2035, can be advanced by maximum of two years if BESS costs are reduced as indicated above.

To effectively reduce curtailment, it is essential to implement the measures outlined in Chapter 14 of the Draft LTGEP 2025-2044. Demand-side initiatives, such as offering promotional tariffs on Sundays and holidays in exchange for a rotational working day for industries, can help mitigate curtailment effects on Sundays. Additionally, as wind penetration increases, evaluating seasonal storage solutions that enable energy shifting across months, rather than just daily shifting, will be crucial.

Section B

The impacts of various given assumptions in capital costing and operational impacts in deviation to the content of LTGEP report are illustrated below with reference to the discussions during the meeting with the CEB and PUCSL on 2024-03-03 .

Scenario	PV Cost of Investment (MUSD)	PV Cost of Operation (MUSD)	Total PV Cost (MUSD)	Rank
Impact of Cost projection ,75% SNSP limited, Quoted LNG Infrastructure Price				
Scenario 3 (Base Case)	8,028	5,691	13,719	2
Scenario 5 (80% RE)	9,104	5,305	14,409	3
Scenario 7 (Reference)	6,197	7,235	13,432	1
Impact of Cost projection, No limit in SNSP, Quoted LNG Infrastructure Price				
Scenario 3 (Base Case)	8,028	5,474	13,502	2
Scenario 5 (80% RE)	9,104	4,927	14,031	3
Scenario 7 (Reference)	6,197	7,180	13,377	1
Impact of Cost projection, No limit in SNSP, Quoted LNG Infrastructure, BESS 20 years(no degradation)				
Scenario 3 (Base Case)	7,914	5,474	13,388	2
Scenario 5 (80% RE)	8,906	4,927	13,833	3
Scenario 7 (Reference)	6,187	7,180	13,367	1
Impact of Cost projection, No limit in SNSP, Non Availability of LNG, BESS 20 years(no degradation)				
Scenario 3 (Base Case)	7,108	7,189	14,297	1
Scenario 5 (80% RE)	8,278	6,198	14,476	2
Scenario 7 (Reference)	5,723	10,667	16,390	3

It is to be noted that the plant schedule identified in Base Case Plan of Draft LTGEP 2025-2044 remains the least cost solution under all assumptions in compliance with General Policy Guidelines issued for the electricity sector. In the event of natural gas not been made available the present value cost shall be higher for all scenarios. Hence ensuring the supply of natural gas infrastructure, renewable energy and storage projects on time at quantities planned in Base Case Plan shall be critical.

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இலங்கைப் பொதுப் பயன்பாடுகள் ஆணைக்குழு
PUBLIC UTILITIES COMMISSION OF SRI LANKA

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දිනය / திகதி / Date 15th May 2025

Authorized officer
For License No. EL/T/25/02
Additional General Manager - Transmission
Ceylon Electricity Board
Sir Chittampalam A. Gardiner Mawatha
Colombo 02.

Long Term Generation Expansion Plan 2025 - 2044

This refers to the submission of the Draft Long Term Generation Expansion Plan 2025 - 2044 vide the letter (Ref:GP/CE/EXPAN-2023) dated 04th September 2024, and to the response vide letter (Ref: GP/CE/EXPAN-101) dated 10th March 2025, for the direction made by the Commission.

The Commission herewith grants the approval for the Long Term Generation Expansion Plan 2025-2044, subject to the following conditions,

The following shall be included in the plan, and the final document shall be submitted to the Commission.

1. Explore the possibility of advancing/expediting the procurement of the Battery Energy Storage System (BESS) included in the plant schedule of Base Case, considering the unforeseen growth in distributed renewable energy resources and declined prices of the BESS, and update the plant schedule of the Base Case accordingly. Also, as mentioned in the letter (Ref: GP/CE/EXPAN/2023) dated 18th December 2024, the capacity of 100MW/50MWh BESS, which has been scheduled to be added to the system in 2026, shall be revised as 100MW/100MWh.
2. Mention the source of the capital costs of the Battery Energy Storage Systems (BESS), depicted in the Table 5.6 (Parameters of Battery Energy Storage Systems)
3. The Commission has noticed a press release published by CEB on 21st February 2025, mentioning that CEB plans to advance the Maha Oya Pumped Storage Hydropower project, which is scheduled to be commissioned in 2034 in the LTGEP 2025-2044. If CEB plans to advance the above Pumped Storage Hydropower project, update the plant schedule of the Base Case accordingly.
4. Mention the reasons for the changes (adjustments to the commissioning year, exclusion of Wewathenna Pump Storage Plant, increase in capital cost) in the planned Pumped Storage Hydropower plants, as compared to the plant schedule of LTGEP 2023-2042, under section 5.11.2 (Pumped Hydro Storage Development)
5. If the planned implementation year for the HVDC interconnection is revised according to the MoU signed on 05th April 2025, between India and Sri Lanka for Implementation of HVDC Interconnection for Import/Export of Power, update the plant schedule of the Base Case accordingly. If there is no change, mention the reason for the delay in implementing the HVDC interconnection compared to the plant schedule of HVDC interconnection Scenario in LTGEP 2023-2042, under Section 6.2 (Infrastructure Development)

06.වන මහල, ලංකා බැංකු වෙළඳ කුළුණ, 28. ශාන්ත මයිකල් පාර, කොළඹ 03.
06 ஆவது மாடி, இலங்கை வங்கி வர்த்தகக் கோபுரம், 28, செள் மைக்கல் வீதி, கொழும்பு 03.
Level 06, BOC Merchant Tower, 28, St. Michael's Road, Colombo 03, Sri Lanka.

Tel : +94 11 2392607/8 Fax : +94 11 2392641 E-mail: info@pucsl.gov.lk Web: www.pucsl.gov.lk

සභාපති / தலைவர் / Chairman +94 11 2392606
අධ්‍යක්ෂ ජනරාල් / பணிப்பாளர் நாயகம் / Director General +94 11 2392606

6. Mention the identified candidate sites for the Nuclear Plant, under Section 4.4.2 (Nuclear Power Plants)
7. Include estimated plant factors and respective specific costs of candidate ORE technologies, Under Section 5.10 (Operational Study for Renewable Energy Integration)
8. The supplementary information and clarifications provided through the following letters of CEB, in response to the request of clarifications/directions issued by the PUCSL, shall be included in the final document of Long Term Generation Expansion Plan 2025-20244.
    - Letter (Ref: GP/CE/EXPAN/2023) dated 21st November 2024
    - Letter (Ref: GP/CE/EXPAN/2023) dated 18th December 2024
    - Letter (Ref: GP/CE/EXPAN/2023) dated 10th March 2025

Also, the Commission recommends the execution of the following actions during the implementation of the Long Term Generation Expansion Plan 2025 – 2044

1. Liquefied Natural Gas (LNG) procurement shall be carried out based on the least cost principle, considering the prospective variations in natural gas demand and considering both capital and fuel costs in procurement options. Further, it shall be ensured that the LNG fuel procurement method and associated investments in LNG infrastructure do not result any economic loss to the country.
2. Potential solutions shall be explored to reduce possible curtailments occurring on Sundays and public holidays.
3. To minimize RE curtailment in the future, feasibility studies shall be conducted to explore long-duration energy storage solutions capable of shifting energy across months, rather than focusing solely on daily renewable energy shifting.

Further, the following input details to be used in the next planning study shall be submitted to the Commission for verification though a consultation process, prior to the next planning study.

1. Cost Details, operation characteristics and construction duration of the Thermal Expansion Candidates with relevant sources.
2. Cost Details (Capital and Fixed O&M Costs) and construction duration of the Renewable Energy Technologies with relevant sources
3. Fuel prices with the basis of deriving the prices
4. Cost of externalities (for both thermal and renewable technologies)

Damitha Kumarasinghe
Director General

ISSN 2989-0012